General Requirements for Instrumentation

MP 32-P-01

December 1997

Scope

This document presents the general requirements for the design, installation and testing of instruments, control systems and related equipment for onshore and offshore petroleum production facilities, petroleum refineries, petrochemical plants and other industrial applications.

Version 0

Table of Contents

Scope **1**

1. References **5**

1.1. MEP–Mobil Engineering Practices 5

1.2. EPT–Mobil Tutorials 6

1.3. API–American Petroleum Institute 6

1.4. ISA–International Society of Measurement & Control 6

1.5. NFPA–National Fire Protection Association 7

2. General **7**

2.1. Microprocessor Technology 7

2.2. Applicable Specifications 7

2.3. Use of API Recommended Practices 7

2.4. Codes and Agency Standards 8

2.5. Electronic Preference 8

2.6. Automatic Operation 8

2.7. Failure Requirements 8

3. Modifications to API RP 554 ..... **9**

4. Process Control and Support Systems **10**

4.1. Local and Dedicated Controllers 10

4.2. Analyzers 11

4.3. Package Units 11

4.4. Instrument Air Compressors and Dryers 11

4.5. Electrical Power Supply 11

4.6. Interlocks and Shutdown Systems 12

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4.7. Burner Management Systems 13
4.8. Tank Gauging Systems 13
4.9. Blending Systems 13
4.10. Custody Transfer Systems 14
4.11. Metering Facilities 14
5. Infrastructure, Safety and Equipment Protection 14
5.1. Control Room 14
5.2. Public Address and Emergency Alarm Systems 15
5.3. PABX (Private Automatic Branch Telephone Exchange) System 15
5.4. Instrument Locations 15
5.5. Electrical Area Classifications 16
5.6. Instrument Grounding 16
5.7. Seismic Testing 16
5.8. Piping and Wiring 16
5.9. Pressurization 17
5.10. Winterizing and Heat Tracing 17
5.11. Instrument Seals 17
5.12. Fire Protection of Instruments 18
5.13. Painting 18
6. Instrument and Control Loop Identification 18
6.1. Drawing Symbols 18
6.2. Tag Numbers 19
6.3. Tags and Nameplates 19
7. Drawings 19
7.1. Instrument Location Drawings 19

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7.2. Piping and Wiring Drawings 20
7.3. Control Room Drawings 21
8. Procurement Data 21
8.1. Instrument Index 21
8.2. Procurement Status Report 22
8.3. Point Index 22
8.4. Source of Component Supply 23
8.5. Supplier's Drawings and Data 23
9. Calculations 23
9.1. Sizing Calculations 23
9.2. Sound Level Calculations 24
10. Field Testing and Calibration 24
10.1. Alarms and Interlocks 24
Appendix 25

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1. References

The following publications form a part of this Practice. Unless otherwise specified herein, use the latest edition.

1.1. MEP–Mobil Engineering Practices

MP 00-P-04	Winterizing & Heat Tracing
MP 00-P-05	Noise Control
MP 00-P-82	Packaged Units-General Requirements
MP 01-P-10	Blast-Resistant Buildings
MP 32-P-01	General Requirements for Instrumentation
MP 32-P-02	Process Measurement Instrumentation (API 551)
MP 32-P-03	Transmission Systems
MP 32-P-04	Control Valves and Actuators
MP 32-P-05	Panels, Enclosures and Video Display Consoles
MP 32-P-06	Process Analyzers
MP 32-P-07	Safety Interlock Systems and Alarms
MP 32-P-08	Control Centers
MP 32-P-09	Heater Controls
MP 32-P-10	Wellhead Shutdown and Hydraulic Control Panels
MP 32-P-11	Compressor Controls
MP 32-P-12	Burner Management Systems
MP 32-P-13	Inst. Inspection, Testing, Calibration, Pre-Commissioning
MP 32-P-14	Programmable Logic Controllers
MP 32-P-15	TMR Safety Systems
MP 32-P-16	Distributed Control Systems
MP 32-P-17	Control of Simple Distillation Towers
MP 32-P-18	Product Blending Systems
MP 32-P-19	Instrumentation Piping and Tubing Fittings
MP 32-P-20	Lease Automatic Custody Transfer Unit
MP 32-P-21	Wiring for Instrumentation and Digital Systems

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MP 32-P-22	Storage Tank Inventory Instrumentation
MP 33-P-06	Electrical - Pressurizing Systems for Buildings
MP 33-P-16	Electrical - AC Uninterruptible Power Supply (UPS) System
MP 33-P-25	Electrical - Lighting, Receptacles and Associated Equipment
MP 35-P-01	Painting - General Requirements
MP 41-P-10	Compressed Air Dryer-Regenerative Type
MP 70-P-01	Loss Prevention - Facilities
MP 70-P-05	Fireproofing

1.2. EPT–Mobil Tutorials

EPT 06-T-07	Supplemental Power Systems for Essential Electrical Loads

1.3. API–American Petroleum Institute

API TP 555	Process Analyzers First Edition
API RP 14C	Recommended Practice for Analysis, Design, Installation, and Testing of Basic Surface Safety Systems for Offshore Production Platforms Fifth Edition; Errata - 1994
API RP 551	Process Measurement Instrumentation First Edition
API RP 554	Process Instrumentation and Control First Edition

1.4. ISA–International Society of Measurement & Control

ISA RP7.1	Pneumatic Control Circuit Pressure Test; (Approved July 1, 1956) Superseded by: S7.0.01: 1996
ISA RP12.4	Pressurized Enclosures
ISA S5.1	Instrumentation Symbols and Identification R(1992)
ISA S5.4	Instrument Loop Diagrams
ISA S20	Specification Forms for Process Measurement and Control Instruments, Primary Elements and Control Valves

1.5. NFPA–National Fire Protection Association

NFPA 72	National Fire Alarm Code
NFPA 496	Standard for Purged and Pressurized Enclosures for Electrical Equipment (National Fire Codes, vol. 7)
NFPA 8501	Standard for Single Burner Boiler Operation (Formerly NFPA 85A)
NFPA 8502	Standard for the Prevention of Furnace Explosions/Implosions in Multiple Burner Boilers Revision and Renumbering of ANSI/NFPA 85C-1991; Errata 03/01/1996

2. General

The design, installation and testing of instruments, control systems and related equipment for onshore and offshore petroleum production facilities, refineries, petrochemical plants and other industrial applications shall be in accordance with requirements of this Mobil Engineering Practice (MEP), unless superceded by more stringent local regulations.

2.1. Microprocessor Technology

Mobil uses proven, cost-effective microprocessor technology in control systems for all projects. Distributed digital instrumentation/control systems shall be part of the overall system design for new plants and major upgrades.

2.2. Applicable Specifications

Instrumentation shall conform to the specific requirements of this Practice, as well as to the requirements of all other applicable Practices, unless otherwise defined by the project specifications or other project documents specifying exceptions or modifications. Examples may include purchase specifications, loop drawings and agreed-upon minutes of meetings. Any exceptions shall be tabulated during the course of the project and incorporated in the control systems specifications.

2.3. Use of API Recommended Practices

The Practices on Instrumentation, MEP Series 32 (see Appendix), are based on API Recommended Practices Series RP 55x. Specific exceptions and modifications are noted in individual MEPS. Where no modifications are made, those practices described in API Recommended Practices as "advisable," "most common" and so forth shall be considered project requirements. When a conflict exists between the Mobil Engineering Practices

(MEPS) and the API RPs, the MEPS shall be followed. The term "approval" means written approval.

2.4. Codes and Agency Standards

Instrumentation shall meet the requirements of applicable national and local codes. The contractor shall certify in writing that all of these requirements have been met.

2.5. Electronic Preference

In case of expansions of existing control rooms and process unit additions, electronic instrumentation shall be installed, even though existing equipment may be pneumatic. For integration into a Distributed Control System (DCS), electronic transmitters shall replace existing pneumatic transmitters.

Pneumatic instruments may be considered for use for the following reasons:

1. Division 1 areas
2. Simplicity/durability
3. Local control loops
4. Unavailability of electrical power

Pneumatic instruments shall not be used where fast response time is required.

2.6. Automatic Operation

Process units, offsite units, steam generation facilities and utilities requiring minimum operator interaction during normal plant operation shall be instrumented for automatic operation where practical. Sufficient data shall be provided to allow the operator to act effectively during a major plant upset. Local control panels shall be furnished as necessary to enable operations personnel to safely start process equipment.

2.7. Failure Requirements

All instruments, pneumatic or electronic, shall fail to the safest position or lock in place upon air or power failure as shown on the piping and instrument diagrams. Control valves that are required to fail safe in air failure shall be spring assisted. The use of accumulators to meet control valve fail-safe conditions shall be minimized. When accumulators are used, the supplier shall furnish the sizing calculations. Project personnel shall have final approval of the failure position of all instruments and related components. Temperature controllers shall fail in the safest direction upon thermocouple or power circuit failure.

Suppliers of electronic instrumentation and microprocessor-based control systems shall supply the following information so that failure action analysis can be made:

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1. Maximum time (seconds or minutes) the power source can be interrupted without disruption of control circuit operations.
2. Quality of power supply required (in terms of maximum and minimum voltage level) and maximum ripple that can be tolerated (in millivolts, peak-to-peak).
3. Action of the instruments upon re-establishment of power; for example, drive full-scale up, drive full-scale down or lock in place.

Particular attention shall be made to verifying that failure requirements are met for solid-state devices such as programmable controllers.

3. Modifications to API RP 554

The following modifications and additions to API Recommended Practices shall apply. The paragraph numbers refer to specific paragraphs in API RP 554.

2.2.2. Addition

All controllers shall be three mode controllers.

All secondary controllers in a cascade system shall have indicating tracking setpoints. The controlled secondary variable shall be continuously indicated. Level controllers that regulate feedstreams to other processing vessels shall be cascade control loops and shall be furnished with set-point limiters.

All electronic analog controllers shall be capable of supervisory control by a host computer unless otherwise approved by the project control system engineer.

All controllers shall have balanceless, bumpless transfer from manual to automatic and automatic to manual.

Pneumatic controllers with three-position transfer switches and regulators shall be used. If the instrument is of the tracking type, or if it has a true deviation meter that permits bumpless transfer from both manual to automatic and automatic to manual positions, the seal position is not needed.

All electronic controllers shall be provided with balanceless, bumpless automatic/manual switching.

2.2.3. Modification

Controllers shall be mounted in the central control room or in satellite buildings, except in cases meeting the stipulations noted in Paragraph 4.1 of this MEP for locally mounted controls.

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Pneumatic controllers designed for a control room location shall not be mounted at the control valve except with approval.

Controllers shall not be mounted to compressor skids or other equipment subject to vibration or on control valves that are subject to vibration. Transmitters with vibration dampeners can be considered to transmit signals to controllers. Local pneumatic controllers shall be provided with an accessible set-point adjustment and an accessible automatic/manual switch and regulator.

4. Process Control and Support Systems

The control system shall be a distributed, digital microprocessor-based network. It shall be designed for flexible, reliable, high-speed process communications configured for centralized control but adaptable to sectionalized control centers within a clearly defined hierarchy. Operator interaction with the process shall be accomplished with a number of operator stations, each consisting of a color Cathode Ray Tube (CRT) display, functional keyboard and other similar devices such as touch screen, mouse, trackball or light pen for operator requests and inputs.

A Control And Information System (CAIS) shall be provided. It shall consist of a distributed digital control system, one or more computers for advanced control and/or management information and subsystems including tank gauging, analyzers, blending, laboratory data, custody transfer and package unit control systems. A dual data communication link shall connect all parts of the system and shall provide automatic switchover in the event of a link failure.

4.1. Local and Dedicated Controllers

Wherever practical, dedicated and other local controllers shall be of microprocessor-based design and compatible with the central control system for communication and interaction.

Controllers shall not be locally mounted unless economic or application requirements justify the use of local pneumatic instruments and shall require approval. All locally mounted controllers shall be of the indicating type with auto/manual facilities. Locally mounted Input/Output (I/O) electronics require approval. Local controllers shall be housed to meet the manufacturer's recommended environmental requirements (e.g., maximum temperature and humidity conditions).

Specialized control and information requirements shall be satisfied by microprocessor-based dedicated systems. These systems shall have the capability to:

- Operate as stand-alone systems independent of the DCS or the computer system.
- Be linked to the CAIS or the plant network.

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4.2. Analyzers

Analyzers shall conform to MP 32-P-06 (also refer to API TP 555).

Analyzers shall only be used when required by the process control scheme and/or regulatory bodies. When used, they shall be installed in a manner to facilitate proper maintenance and operation.

4.3. Package Units

Package units shall conform to MP 00-P-82.

Particular attention shall be given to package units to ensure that the control systems designs are consistent with the main process units and the quality of the instruments used is of an equal standard. Wherever possible, the same instruments used for main process units shall be used in packaged units. They shall fulfill the basic requirements of the project and be integrated into the central control room data communications network. The package unit supplier shall pay particular attention to compliance with project requirements for accessibility and ease of maintenance. The project control systems engineer shall review all appropriate package unit drawings.

4.4. Instrument Air Compressors and Dryers

Instrument Air Compressors and Dryers shall conform to MP 41-P-10.

Instrument air supply and drying equipment shall be in accordance with applicable specifications. Systems design shall be based on supplying air that is clean, dry and free of oil vapors and shall include a dryer outlet dew point at least 10ºC (18ºF) below the lowest ambient temperature. Normally, two oil-free instrument air compressors with different types of drives shall be provided.

4.5. Electrical Power Supply

Electrical power to the control room shall be limited to that voltage required for instruments and lighting. Use of higher voltage levels requires approval. Lighting systems shall have adequate filtering to eliminate electrical noise, as required in MP 33-P-25.

Instrument power shall be supplied by Uninterruptable Power Supplies (UPS), unless otherwise specified, as required in MP 33-P-16. Redundant UPS systems, with separate electrical feeds and redundant instrument power supplies fed from the separate UPS systems, shall be used to eliminate single points of failure in instrument power systems. Analyzer power requirements are shown in MP 32-P-06.

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4.6. Interlocks and Shutdown Systems

4.6.1. Design Requirements

Interlock and shutdown systems shall be installed as shown on the Piping and Instrument Diagrams (P&ID) or as outlined in the cause and effect drawings or per project specifications.

- All digital interlock and shutdown systems shall have a standard communication interface to the selected DCS and CAIS systems.
  - Operator interface displays shall be provided.
  - Maintenance displays, accessible through the operator station, shall be provided.
- All interlock and logic systems shall be in accordance with MP 32-P-07.
- Interlock and shutdown systems shall be designed to avoid trips caused by process transients or power dips of short duration. The exact duration of these transients and power dips shall be specified by project; for example, a 10-second delay for low-flow trip to heaters and a one-second delay on power dips. Power system design for interlock and shutdown systems shall meet the requirements in Section 4.5 of this MEP.
- The contractor shall be responsible for the compatibility of all elements of an interlock and shutdown system and for conformance of the total system to the requirements of the project. When the interlock and safety system cannot be shut down for testing at acceptable frequency to meet Mobil reliability standards, the system shall be designed to facilitate online trip testing of shutdown loops to the final control device.
- The contractor shall be responsible for application of the requirements listed above to interlock systems supplied with packaged units.

4.6.2. Failure States

All instruments, pneumatic or electronic, shall fail to the safe position or lock in place upon air, hydraulic or electrical power failure.

Shutdown valves, blowdown valves and control valves shall have spring-return actuators.

The use of accumulators to meet control valve fail-safe conditions requires written approval.

All valves and their respective control cabling, tubing and associated field equipment shall be fireproofed if the valves are required to remain operable during a fire, in order to accomplish a sequenced shutdown.

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Shutdown valve failure analysis shall consider all equipment in the loop, including solenoid valves.

Suppliers of electronic instrumentation shall supply at least the following information in order for a failure action analysis to be made:

1. Maximum time the power source can be interrupted without disruption of control circuit operations
2. Quality of power supply required (in terms of maximum and minimum voltage level), maximum ripple that can be tolerated (in millivolts, peak to peak) and maximum harmonic distortion of the AC power source
3. Action of the instruments upon re-establishment of power, which includes drive full-scale up, drive full-scale down or lock in place

Platform Safety Shutdown Systems (PSSDS) and related interlocks shall be designed to conform with API RP 14C and as outlined in the job specifications. Safety Analysis Function Evaluation (SAFE) charts as specified by API RP 14C are required as a part of the shutdown system data package.

Fire protection/safety systems shall be zoned and designed in accordance with MP 70-P-01 or more stringent local codes.

4.7. Burner Management Systems

Microprocessor-based burner management systems shall be used with boilers (refer to MP 32-P-12). For process heater requirements refer to MP 32-P-09. All burner management systems shall have a standard communication interface to the selected DCS and CAIS systems. Operator interface displays as well as maintenance displays (accessible through the operator station) shall be provided. (Also refer to NFPA 8501 and NFPA 8502.)

4.8. Tank Gauging Systems

Tank gauging display systems shall be of the microprocessor-based type and shall be capable of communication with the selected DCS and CAIS systems. Operator interface displays as well as maintenance displays (accessible through the operator station) shall be provided. All tanks shall be furnished with tank gauging and temperature equipment in accordance with MP 32-P-22. They shall also be furnished with a ground reading level instrument and local thermometers.

4.9. Blending Systems

Product blending systems shall be of the microprocessor-based type and shall be capable of communication with the selected DCS and CAIS systems. Operator interface displays as well as maintenance displays (accessible through the operator station) shall be provided. These systems shall be designed in accordance with MP 32-P-18.

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4.10. Custody Transfer Systems

Custody transfer systems, including meter provers, shall be capable of communication with the selected DCS and CAIS systems as applicable and as defined in the job specifications. Operator interface displays (accessible through the operator station) shall be provided.

In some countries, servo-operated tank gauges, coupled with a microprocessor-based control systems, are recognized as being sufficiently accurate to meet custody transfer requirements. Configurations intended to fulfill these requirements shall be submitted for approval prior to purchase and installation.

4.11. Metering Facilities

Metering systems, complete with high-accuracy flowmeters, microprocessor-based prover systems and panel-mounted equipment, shall be capable of communication with the selected DCS and CAIS systems. Operator interface displays as well as maintenance displays (accessible through the operator station) shall be provided.

5. Infrastructure, Safety and Equipment Protection

Requirements in this Section shall be followed to ensure protection of facilities.

5.1. Control Room

Ideally, the control room and Satellite Instrument House/Remote Instrument Enclosure (SIH/RIE) shall be located 150 m (500 ft) away from a blast source. For closer locations, blast-resistant construction shall be used in accordance with MP 01-P-10.

A control room, computer room, SIH/RIE, office and maintenance and storage space shall be provided to house the CAIS activity. The facilities and equipment shall be completed in time to permit adequate computer system testing prior to startup.

For systems that shall be located in refineries, the system specification shall require bidders to define the acceptable levels of sulfur dioxide and hydrogen sulfide in locations where equipment is to be housed. Depending on the existing environment, it may be necessary to provide supplemental chemical filtration to reduce contamination to acceptable levels.

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5.2. Public Address and Emergency Alarm Systems

All manned offshore platforms shall support a Public Address and Emergency Alarm System (PAEAS). The PAEAS shall permit:

1. Announcement of important messages
2. Tone signals and colored flashing lights

If required by the job specifications, the following minimum signal tones, in addition to voice command, shall be provided in ascending order of priority:

- Process emergency
- Fire
- Abandon platform

The above signal tones shall be initiated by PSSDS, the process monitoring and control system, and the fire and gas monitoring system.

In noisy areas, the color of the flashing light shall convey the preceding messages.

5.3. PABX (Private Automatic Branch Telephone Exchange) System

All manned platforms (and to some extent unmanned platforms) shall have a Private Automatic Branch Telephone Exchange (PABX) as requested by the job specifications. The individual platform PABX shall be an integral part of the telephone network connecting all platforms in the area and connecting to shore. The communications between the platforms and a microwave link with VHF radio backup to the shore shall be covered by the job specifications.

EPT 06-T-07 and NFPA 72 shall be the basis for the development of the job specifications, unless otherwise defined.

5.4. Instrument Locations

The location of instruments and instrument connections, including terminal and junction boxes, control equipment and relief valves, shall permit easy access from deck/grade, permanent platforms or stairways for operation, inspection and maintenance. Locations shall also minimize the possibility of damage from passing or falling objects and from fire. A permanent platform may not be required where a clear area allows access from a ladder or portable platform to an instrument or element not more than 4.5 m (15 ft) above grade, however, all instruments so mounted shall be subject to approval. All appropriate construction drawings and models shall be reviewed by the project control system engineer. All indicating instruments shall be installed to be readable from grade and/or the related operational area.

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5.5. Electrical Area Classifications

All electrical or electronic instrumentation equipment shall conform to the requirements for installation in accordance with the area classification. Enclosures or cabling and grounding systems for all field-mounted or local panel-mounted electrical or electronic instruments (or instruments having electrical connections) shall conform to the requirements of the electrical classification of the area of installation. Housings located in unclassified outdoor areas or in unprotected areas shall meet the specifications of NEMA 4X as a minimum.

Special attention shall be given to those instrument installations that meet all area classifications and code requirements but may serve as a path for flammable gases or liquids to unclassified areas, even under normal conditions. In addition to MP 32-P-21 (for cables and raceways), these paths may be formed by:

1. Tubing runs
2. Air lines to pressure balance valves without isolation relays or dual diaphragms with a vent
3. Air and lines to explosion-proof housings designed for internal leaks rather than external sources of hydrocarbons; for example, an analyzer housing

5.6. Instrument Grounding

The DC ground reference point for all signals from electronic instrumentation shall be at a single common point in the SIH/RIE or control room, separate from the plant ground grid. Where multiple grounds are required by local codes, these earthing points shall be separate (electrically isolated) from the plant grid. When multiple grounds are required in an instrument wiring loop, galvanically isolated devices shall be used for loop coupling.

5.7. Seismic Testing

When required by project specifications, instrumentation shall be subject to seismic testing. The standards used for testing and the necessary certification shall be developed by the contractor and submitted for approval.

5.8. Piping and Wiring

No process fluids, process gas, chemical or steam (except for heating purposes) shall be piped into the control room.

Field piping and tubing shall conform to MP 32-P-19.

Where underground routing in the field is not practical, overhead cable and tubing shall be routed in vertical cable racks. These cable racks shall be located in areas not vulnerable to fire exposure. Routing shall not be over pumps, compressors or adjacent to fired heaters.

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If a cable rack is in a fire exposure area, it shall be fireproofed in accordance with MP 70-P-05. Vertical cable racks minimize the exposure of cable runs to mechanical and fire damage. Where it can be demonstrated that vertical racks are mechanically impractical or uneconomical, horizontal racks may be installed, subject to approval.

Cable shall be routed to enter the control house in at least two (preferably four) separate locations so that fire or physical damage to a cable run and rack shall affect no more than 50 percent (preferably 25 percent) of the operation. As far as practical, these cables shall be kept separated in the control room. All field measurements shall terminate in separate, cross-connect panels or marshaling racks. Wiring shall be routed from the cross-connect panels or marshaling racks, to the data interface cabinets and operator control stations below the modular floor, while still maintaining separation.

Terminal strips in field junction boxes and control room distribution panels shall be of modular construction. Electrical terminals shall be of the pressure-plate type, with all "live" parts recessed into the insulated block. Terminal strips suitable for the environment (for example, tropic proofing) shall be used as applicable.

The terminal strips shall have separate connections available for test leads or jumpers. All screws and parts in the terminal blocks shall be captive. Construction materials shall be stainless steel or nickel-plated brass for all electrical contacts. Aluminum is preferred for all other metal parts. Terminal screws shall have integral lock washers, as a minimum, or be of tension-designed construction equivalent to a lock washer. All instrumentation terminal strips shall have this type of screw unless otherwise approved by the project control system engineer.

5.9. Pressurization

Pressurization shall conform to the requirements in MP 33-P-06.

Pressurization of instrument enclosures, SIH/RIEs and field control panels for environmental or electrical area classification shall be in accordance with NFPA 496 and ISA RP12.4. Local standards shall prevail where they exceed the requirements of the NFPA or ISA practices.

5.10. Winterizing and Heat Tracing

Winterizing and heat tracing of instruments shall be in accordance with MP 00-P-04 or local practices.

5.11. Instrument Seals

There are three types of instrument sealing methods used to prevent process fluid from damaging the instrument or plugging the lines to the instrument.

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5.11.1. Diaphragm Seals

A method of sealing using a flexible membrane to hold the seal liquid in the instrument and mechanically separating the sealing liquid from the process fluid in accordance with API RP 551, Paragraph 6.3.1.

5.11.2. Liquid Seals

A method of sealing that uses a liquid of a density different from the measured process fluid and that is immiscible with it. The project control systems engineer shall review and approve installation drawings for liquid seals and also approve the type of sealing material.

5.11.3. Process Purge

A method that seals the instrument and sweeps the lines clean of the measured process material. This type of purging system is commonly used on process streams subject to coking, sedimentation or other contaminants that might damage or plug the instrument or its lines.

5.12. Fire Protection of Instruments

Fireproofing of instruments shall be in accordance with MP 32-P-04 and MP 70-P-05. Fireproofing of main instrument runs shall include supports and junction boxes.

5.13. Painting

Control room panels and visible portions of instruments mounted on the panel shall conform to the painting schedule in MP 35-P-01. The manufacturer's standard colors shall be used for all other instrumentation, unless otherwise specified.

6. Instrument and Control Loop Identification

Identification methods shall conform to the requirements in this Section.

6.1. Drawing Symbols

The instrument symbols used in the Piping and Instrument Diagram’s (P&ID’s) provide the basis for all instrument identification and shall be carefully selected and agreed to by the project control systems engineer, the operating company and the contractor as a workable medium (refer to ISA S5.1). These symbols shall take into account all levels of

measurement and control (DCS, local control and computers) and have distinguishing shapes or lines to provide unambiguous identification.

6.2. Tag Numbers

A variety of methods may be used for numbering the instruments and control loops. However, the numbering sequence chosen shall comprehend the size of the project, the processing capability of all of the plant computers (control, maintenance, purchasing, etc.) and the existing plant in expansion projects. The framework of the instrument tag numbering system shall be coordinated with the overall plant equipment numbering system at the time of Process Flow Diagram (PFD) development.

If, in the course of the project, a piece of equipment with an assigned number is deleted, the number shall still be carried on the instrument index, be shown as deleted and not be used again on that project. If two or more pieces of equipment are inadvertently assigned the same number, the number shall be deleted and each piece of equipment, with the corresponding records, shall be assigned a new number.

Data sheets contained in ISA S20 shall be used except where the use of a contractor's data sheet has been approved. If used, the contractor's document shall include, at a minimum, all data required on the ISA data sheets.

6.3. Tags and Nameplates

An identification tag shall be attached to each piece of instrumentation equipment. Tags for field-mounted instruments shall be of 1.3 mm (16 U.S. gauge) stainless steel (or equivalent) unless approval is given for the use of laminated plastic. All field tags shall be attached by 1.3 mm (16 U.S. gauge) wire or stainless steel drive screws. Rectangular tags, a minimum of 25 mm by 50 mm (1 in by 2 in), shall be used for each piece of instrumentation unless otherwise specified in the project specifications. Plastic tag strips shall be used in all junction boxes and behind control boards and shall be secured by metal fasteners, alpha-cyanoacrylate adhesive or other approved means. All lettering shall be at least 5 mm ($^{3}/_{16}$ in) high. Nameplate color and nomenclature shall be submitted for approval.

7. Drawings

The contractor shall furnish standard location and schematic drawings.

7.1. Instrument Location Drawings

Instrument drawings shall show the locations (elevations and line or vessel number) of all instruments except pressure gauges and local thermometers. Pneumatic instruments and

air lines shall be shown on one drawing or a series of drawings. Electronic instruments and electrical wiring shall be shown on a separate drawing or a series of drawings. Instrument equipment involving both pneumatic and electronic systems (such as electronic-to-pneumatic units and control valves) shall be shown on both drawings. Routing of the thermocouple leads shall be shown in elevation. All drawings shall have an alpha-numeric grid to allow for instrument cross-referencing and location. When a series of drawings is used, all drawings shall have the same series number with separate sheet numbers or letters. For multiple-page drawings, appropriate match marks shall be shown on the grids.

Location drawings shall indicate instruments and auxiliaries that require fire or weather protection. Instrument air drawings shall show routing of the instrument air header, air branch supply leads, block valves and controlled and transmitted air lines.

7.2. Piping and Wiring Drawings

Upon mechanical completion acceptance, all drawings and diagrams shall be corrected to as-built configuration and made available to operating personnel for unit checkout and startup.

7.2.1. Hookup Drawings

The contractor shall prepare, at a minimum, three types of hookup drawings (see API RP 551):

1. Instrument process piping
2. Electrical wiring
3. Instrument air piping

Drawings may include more than one tag number for identical installations and tables may be used to distinguish details.

7.2.2. Wiring Diagrams and Schematics

Wiring diagrams shall be furnished for all instrument systems. Wiring diagrams shall show all terminations and cable identifications. Computerized wring schedules shall not be provided in lieu of wiring diagrams and schematics. Layout drawings shall be provided for all junction boxes and termination panels. Schematics shall be provided for all circuits showing all elements, terminations and wires. The use of typical electrical drawings shall be subject to approval.

7.2.3. Logic Diagrams

Interlock, shutdown and safety system logic diagrams shall also be furnished. All logic diagrams for these systems shall include block flow diagrams and a written description of the proposed operation. Each sequence trip and alarm shall be described in detail. When unit control systems have direct or

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ancillary effects, these effects shall be described. Examples are boiler combustion control effects on flame lightoff and fuel interlocks or process control effects on the compressor shutdown and interlock system. All wiring and logic diagrams shall be submitted for approval prior to construction.

7.2.4. Loop Drawings

Loop drawings and proposed formats shall be in accordance with ISA S5.4. The contractor's standard may be used as a base, provided all data shown in ISA S5.4 are included on sheets that have a similar format. A loop diagram showing all terminations and cable identifications shall be prepared for each instrument loop. Each loop drawing shall show and identify all items interconnected in an instrument signal circuit, including power supply terminals and computer terminals. Loop diagrams shall be large enough so that the dense wiring interconnections are clearly shown. Interconnections between power supplies shall be shown on a separate schematic. These schematics are required for both pneumatic and electronic loops. Related wiring shall be referenced on the loop diagram.

7.3. Control Room Drawings

The contractor shall prepare and submit for approval drawings of control room layouts showing locations of operator consoles, interface cabinetry, peripheral equipment, doors and other items required by the project specifications. Provisions for future changes, if required by the project specifications, shall be clearly indicated on the drawings.

The contractor shall prepare detailed drawings of interconnecting wiring that conform to the approved control room layout.

The contractor shall provide specifications for power, floor loading, floor area, heating, ventilation and air conditioning, as well as heat dissipation and sound level data for the system and its peripherals. Fire protection/safety systems shall be zoned in accordance with local codes and system hardware configurations.

8. Procurement Data

Procurement data shall be required as described in this Section.

8.1. Instrument Index

The contractor shall furnish a master instrument index.

For basic project data, each index sheet shall display a title line showing the revision number, date, area number (unit number), unit title and sheet number. For detailed

instrumentation data, horizontal line entries are made for each unit (instrument, module, cabinet, etc.) and include tag number, service and remarks.

Computer programs and printouts shall be used for the instrument index. On occasion, when a licenser or packaged unit supplier provides data sheets describing the furnished equipment, the contractor may use different instrument numbers. In such cases, the instrument index shall show a cross-reference between the contractor's index sheet and instrument numbers. The index shall be updated and submitted according to the document schedule defined in the project specifications.

The contractor shall provide an alarm and trip schedule.

8.2. Procurement Status Report

The contractor shall furnish a procurement status report. At a minimum, the status report shall display a title line showing the revision number, date, area number (unit number), unit title and page number. For the instruments, there shall be separate columns for:

1. Instrument type and tag number
2. Total number of items
3. Requisition number
4. Inquiry number
5. Number of supplier inquiries approved
6. Number of purchase orders issued
7. Number of supplier-certified prints received
8. Number of spare-parts lists received

A consolidated summary shall be included for the entire project. Computer programs and printouts shall be used. The status report shall be updated and submitted to the project control systems engineer according to the document schedule defined in the project specifications.

8.3. Point Index

A computer-generated point index shall be used to assist in computer input point and output point selection and control. All documentation, user manuals and tapes of computer programs, required by this Practice, shall be furnished to the project control systems engineer and shall be upgraded to an as-built configuration by the contractor. Sufficient portions of the point index shall be furnished during the engineering phase to permit verification of the programs. These programs allow the project control systems engineer to continually upgrade the documents during the life of the unit.

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8.4. Source of Component Supply

The supplier shall provide, on request, the name and source of the components used in the manufacture of his equipment. The supplier shall not deviate from these stated names and sources of component supply without approval.

8.5. Supplier's Drawings and Data

The contractor shall furnish the required number of copies of the supplier's certified drawings; electric circuit details; complete installation startup and service instructions; complete and detailed field adjustment instructions; maintenance instructions; complete parts list with illustrations; and price list of recommended spare parts, including tag number, catalog number and a serial or model number of each instrument that a part shall fit. The contractor shall furnish a list for cross-referencing the instruments to the supplier's instructions and spare parts. This may be accomplished on the master instrument index.

9. Calculations

Calculations shall be provided as described in this Section.

9.1. Sizing Calculations

The contractor shall provide calculations for orifice plates, control valves, traps and relief valves as they are completed. The equipment shall not be purchased until these calculations are approved. Final plant data books shall have consolidated sections including all of these calculations.

- All symbols used in the calculations shall be identified. References shall be quoted for the equations and methods of calibration used.
- The flow elements shall be sized based on the supplier's standard computer program. Contractors who do not have a computer program shall submit their calculations and calculation sheet format for confirmation. Where a discrepancy occurs, a recognized standard applicable to the location of installation shall be used to resolve it.
- Sizing and sound level prediction of control valves shall be based on the control valve supplier's computer program. The contractor's base program may be used to confirm the supplier's data. Where sizing data appear to be incompatible, the ISA method may be used as a secondary reference.

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9.2. Sound Level Calculations

Sound level calculations are required for all instrumentation devices that generate noise or contribute to the plant sound level. These limits shall be in conformance with MP 00-P-05 and shall be incorporated in the project specifications.

10. Field Testing and Calibration

The contractor shall demonstrate to the project control systems engineer that all instruments and control equipment are properly installed and connected, pressure tested and fully operable.

Test procedures shall require approval. MP 32-P-13 shall be the basis for instrument calibration and acceptance.

Pneumatic tubing shall be leak checked as required by ISA RP7.1.

All tests and calibrations shall be subject to witness and approval by the project control systems engineer.

10.1. Alarms and Interlocks

Alarm settings and interlock action shall be checked for proper operation in the presence of a project representative. All interconnecting wiring on electronic instruments shall be checked for continuity, grounding and shielding (if required) as shown on the approved wiring diagrams.

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Appendix

Table A–1: Equipment Practices–Instrumentation Series

MP 32-P-01	General Requirements for Instrumentation
MP 32-P-02	Process Measurement Instrumentation (API 551)
MP 32-P-03	Transmission Systems
MP 32-P-04	Control Valves and Actuators
MP 32-P-05	Panels, Enclosures and Video Display Consoles
MP 32-P-06	Process Analyzers
MP 32-P-07	Safety Interlock Systems and Alarms
MP 32-P-08	Control Centers
MP 32-P-09	Heater Controls
MP 32-P-10	Wellhead Shutdown and Hydraulic Control Panels
MP 32-P-11	Compressor Controls
MP 32-P-12	Burner Management Systems
MP 32-P-13	Inst. Inspection, Testing, Calibration, Pre-Commissioning
MP 32-P-14	Programmable Logic Controllers
MP 32-P-15	TMR Safety Systems
MP 32-P-16	Distributed Control Systems
MP 32-P-17	Control of Simple Distillation Towers
MP 32-P-18	Product Blending Systems
MP 32-P-19	Instrumentation Piping and Tubing Fittings
MP 32-P-20	Lease Automatic Custody Transfer Unit
MP 32-P-21	Wiring for Instrumentation and Digital Systems
MP 32-P-22	Storage Tank Inventory Instrumentation

Process Measurement and Control

EPT 05-T-06

September 1992 Draft

Version 0

Table of Contents

1. Scope 3

2. References 3

2.1. MEPS–Mobil Engineering Practices 3

2.2. Mobil Tutorials 3

2.3. ANSI–American National Standards Institute 3

2.4. CHILTON–Chilton 3

2.5. ISA–Instrument Society of America 3

3. Principles of Operation 4

3.1. Bourdon Tube 4

3.2. Bellows 4

3.3. Diaphragm 4

3.4. Piston 4

3.5. Electronic 5

3.6. Special Sensors 5

4. Device Selection 5

4.1. Sensors 5

4.2. Pressure Sensor Protection 6

4.3. Pressure Gauges 10

4.4. Pressure Switches 17

4.5. Pressure Transmitters 23

4.6. Pressure Controllers 24

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1. Scope

This tutorial covers equipment types, selection criteria, and operating principles regarding pressure instruments that are frequently used for oil and gas production. The most commonly used types are emphasized; other types are mentioned briefly and references are provided.

2. References

The following Mobil guides and industry publications shall be considered a part of this EPT. Refer to the latest editions unless otherwise specified herein.

2.1. MEPS–Mobil Engineering Practices

MP 32-P-02	Process Measurement Instrumentation

2.2. Mobil Tutorials

EPT 05-T-02	Controllers and Control Theory

2.3. ANSI–American National Standards Institute

ANSI B70.1	Gauges–Pressure Indicating Dial Type–Elastic Element

2.4. CHILTON–Chilton

CHILTON	Instruments Engineer's Handbook (2 Volumes): Process Measurement and Process Control

2.5. ISA–Instrument Society of America

ISA S20	Specification Forms for Process Measurement and Control Instruments, Primary Elements and Control Valves
ISA S51.1	Process Instrumentation Terminology R(1993)

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3. Principles of Operation

There are four types of basic pressure sensors commonly used in the petroleum industry: bourdon tube, diaphragm, bellows, and piston. Each of these sensors responds mechanically to the application of pressure, and, by means of unique linking techniques, provides a direct indication or generates a signal (pneumatic or electronic) representing the applied pressure. More detailed information is provided in Chapter 5 of the Chilton Process Measurement Handbook. Where an electronic signal is required, a strain gauge or capacitance detector is commonly employed in conjunction with one of the above.

3.1. Bourdon Tube

The bourdon tube is the most common type of pressure sensor in use. A basic bourdon tube is manufactured in an arc such that, when pressure is applied, the tube tends to straighten. A detailed description is provided in Section 5.4 of the Chilton Process Measurement Handbook.

3.2. Bellows

The bellows sensor may be as common as the diaphragm because of its similarity to the diaphragm. A bellows is basically a cup or tube with rippled sides such that, when pressure is applied to the inside of the bellows, the bellows tends to extend/lengthen in proportion to the pressure applied. A detailed description is provided in Section 5.3 of the Chilton Process Measurement Handbook.

3.3. Diaphragm

The next most common sensor is the diaphragm. Basically, a diaphragm is a circular flexible plate fixed such that, when a greater pressure is applied to one side, it flexes in proportion to the applied pressure. A detailed description is provided in Section 5.5 of the Chilton Process Measurement Handbook.

3.4. Piston

The piston sensor is most commonly used in switch applications. It is basically a piston and spring arranged in a sleeve such that application of pressure will cause a proportional movement of the piston. An example of this sensor is presented in Section 5.6 of the Chilton Process Measurement Handbook.

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3.5. Electronic

Electronic pressure sensors are unique linking techniques employed with the basic sensors mentioned above. Common types are the strain gauge and the capacitance detector. In either case, the electronic output is normally a 4 to 20 mA signal whose amplitude is proportional to the applied pressure. Refer to Section 5.7 of the Chilton Process Measurement Handbook for specific details.

3.6. Special Sensors

Specialty sensor devices such as high pressure sensors, differential pressure sensors, resonant wire, and manometers are discussed in detail in Chapter 5 of the Chilton Process Measurement Handbook.

4. Device Selection

4.1. Sensors

4.1.1. Bourdon Tube Sensors

1. There are three common types of bourdon tubes, the “C”, the spiral, and the helix. The primary differences among these types are their geometric variations. The “C” type is simple and less expensive to manufacture than the spiral or helix, so it is found in most pressure gauges and some large case controllers and transmitters. The spiral and the helix are more costly to manufacture, but they occupy less space for a given amount of movement and allow smaller instrument cases to be used. In addition, the multiple turns allow thicker material to be used for a given sensitivity, and thus they are less subject to damage from overranging than the “C” type.

2. “C” type bourdon tubes are used for ranges as low as 0 to 100 kPa (0 to 15 psig) and as high as 0 to 10,000 kPa (0 to 1500 psig). They are simple and accurate, and they have good repeatability. On the other hand, they are more bulky and highly subject to damage from overranging.

3. Helical bourdon tubes are used for ranges from as low as 0 to 1300 kPa (0 to 200 psig) to 0 to 40,000 kPa (0 to 6000 psig). Heavy-duty helical bourdons can sometimes tolerate as high as ten times the maximum range pressure.

4. Spiral bourdon tubes are used for both very low ranges and very high ranges. Very sensitive units are manufactured to measure as low as 0 to

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65 kPa (0 to 10 psig), and heavy-duty units can measure up to 0 to 700,000 kPa (0 to 100,000 psig).

4.1.2. Bellows Sensors

1. A bellows sensor can accurately measure much lower pressures than a bourdon tube. Absolute pressure ranges as low as 0 to 100 mm Hg and gauge pressure ranges as low as 0 to 125 mm H_2O (0 to 5 in H_2O) are available. Bellows elements can measure absolute pressure, gauge pressure, vacuum, or differential pressure.

2. Some of the obvious disadvantages of bellows sensors are that they are subject to work hardening and that they are sensitive to ambient temperature variations. In addition, the elastic action of the bellows alone does not provide sufficient power to oppose the pressure, and a spring shall be added to extend the range. Another disadvantage is that the upper range limit of bellows elements is not as high as that of bourdon tubes.

4.1.3. Diaphragm Sensors

1. There are two types of diaphragm elements, elastic and limp. The elastic type uses the stiffness of the diaphragm to oppose the pressure applied. The diaphragm is usually metallic and comes in two different configurations, single and capsular. The single diaphragm is, as its name implies, a single diaphragm either flat or with concentric corrugations. Evacuated capsules are used for absolute pressure reference and single diaphragms for very sensitive measurements.

2. The limp diaphragm can be metallic or non-metallic. It comes only in the single diaphragm form, and it is used to contain pressure and exert a force on an opposing spring. For very low pressures and vacuums, a non-metallic diaphragm is used in conjunction with a spring for measurement.

3. Diaphragm pressure elements are able to measure lower pressures than bourdon tubes. Measurement of absolute and gauge pressures down to 0 to 5 mm H_2O (0 to 0.2 in H_2O) are common. Diaphragm elements can measure absolute pressure, gauge pressure, vacuum or differential pressure; they can be designed to withstand substantial overrange. Diaphragms provide limited movement; this characteristic limits their use in gauges and controllers.

4.2. Pressure Sensor Protection

Certain applications are so severe that the pressure sensor will not remain functional for any reasonable amount of time. For these cases the devices described in the following sections can be used to protect the pressure sensor.

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4.2.1. Diaphragm Seals

1. Diaphragm seals are used to isolate the pressure sensor from the process fluid. This is done when the fluid is toxic, corrosive, dirty (with entrained solids or mud that may plug the instruments), solidifies at ambient temperature, or is extremely cold and may freeze the instrument. The diaphragm seal is a thin, flexible disk that separates the pressure sensor from the process media. The connecting space on the sensor side of the diaphragm is completely filled with a noncompressible liquid. When process pressure is applied, the diaphragm is displaced sufficiently to transmit an equal pressure to the pressure sensor.

2. The three main components of a diaphragm seal are the top housing, bottom housing, and diaphragm, as shown in Figure 1. The bottom housing is in contact with the process fluid; therefore, it shall be made of a material that is compatible with the fluid. The bottom housing also contains the process connection, and some contain a flushing connection to enable the face of the diaphragm to be cleaned.

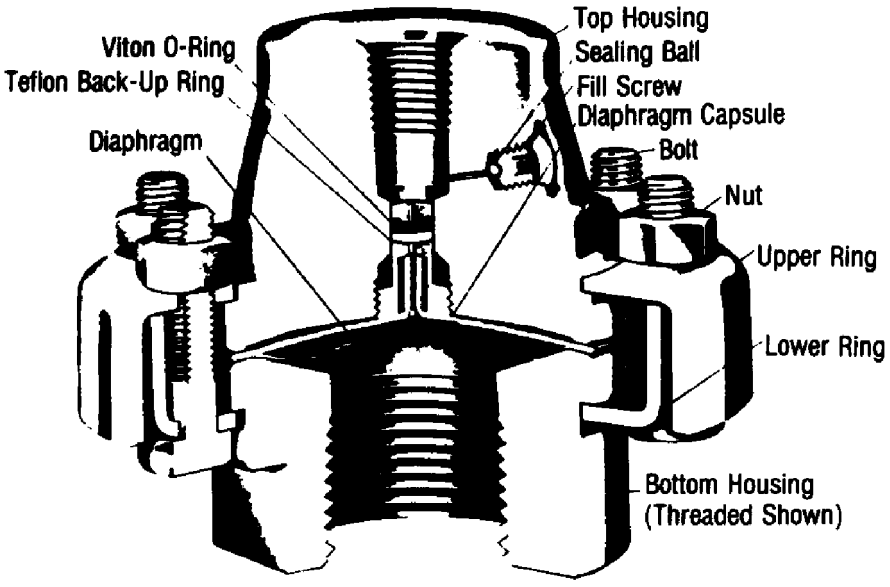

Figure 1: A Schematic of a Diaphragm Seal (Courtesy of Dresser-Ashcroft)

3. The upper housing does not contact the process fluid; it can be made of a less expensive material. The top housing contains the fill liquid and is connected directly to the pressure sensor; alternately, it may be connected by a capillary of up to 7 m (25 ft) to a remote-mounted pressure sensor. The upper housing may have a connection for insertion of the fill liquid, but this is not standard on all designs.

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4. There are several different designs of diaphragms. Many fill liquids are available; they differ mainly in their thermal expansion characteristics. Temperature ranges for fill liquids range from -40 to 816°C (-40 to 1500°F).

5. Diaphragm seals shall be properly filled, and the design shall meet the process requirements. These seals are sensitive to temperature variations, and they lose accuracy when used for vacuum or very low pressure services. Diaphragm seals are also relatively expensive compared to some of the protected devices.

4.2.2. Siphons

1. Siphons are generally used to isolate a hot-process medium from the pressure sensor. The siphon is a metal, tubular device shaped to form a plumber's loop (a low pocket in the tube), as shown in Figure 2. The part above the loop is filled with process fluid that has condensed due to heat exchange with the atmosphere. It can also be filled with a high-boiling-point liquid, such as ethylene glycol or glycerine, which acts as a barrier to the heat contained in the hot gases or steam. These devices also act as pulsation dampeners.

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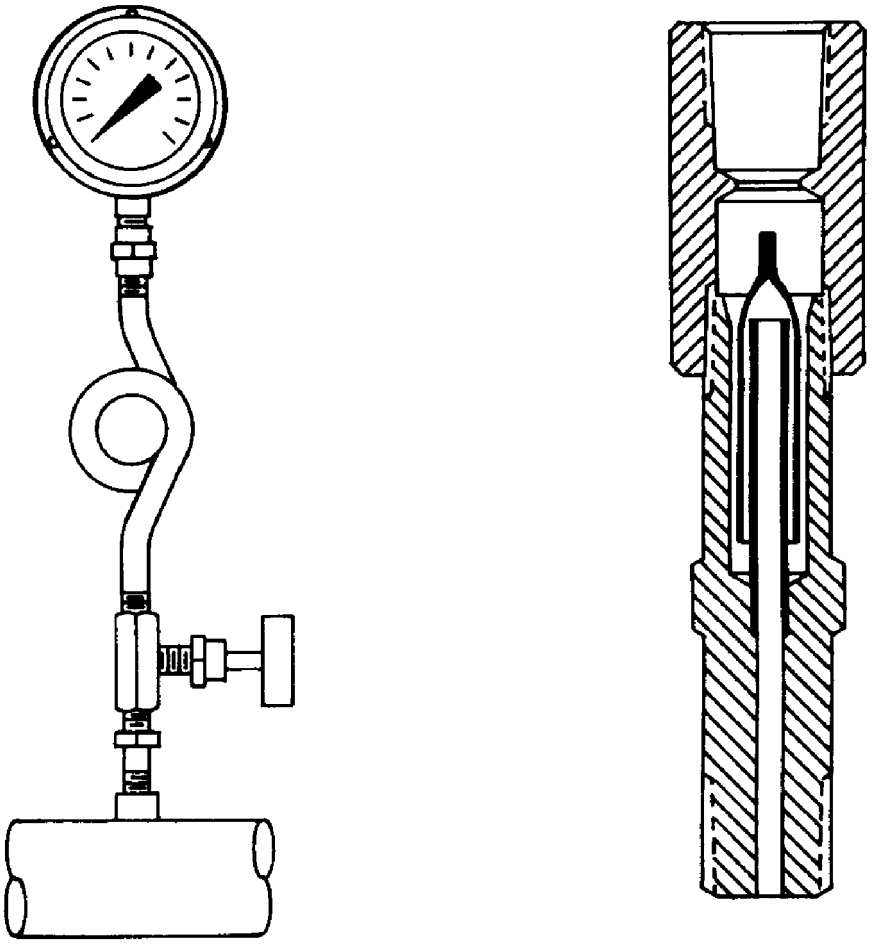

Figure 2: A Schematic of Two Types of Siphon Pressure Sensors (Courtesy of Anderson Greenwood)

2. The path the hot vapor takes to the pressure sensor is relatively long and narrow, with a lot of surface area for cooling. Siphons are needed in most steam services and many hot gas services because many pressure sensors have temperature limits around 82°C (180°F). A piece of tubing that has a 360° bend between its ends is called a pigtail siphon or a line siphon. Another siphon design uses internal passages within a barstock body and is sturdier and more compact, as shown in Figure 2.

4.2.3. Snubbers

1. Snubbers (throttling devices) are commonly used to dampen high frequency pressure fluctuations by putting a restriction in the inlet to the pressure sensor.

2. Adjustable snubbers are the simplest means of providing a restriction. They are special screws that come in several orifice sizes and are inserted into a tapped hole in the base (socket) of the pressure sensor to provide a flow restriction, as shown in Figure 3. Throttling screws shall be ordered in conjunction with the pressure sensor.

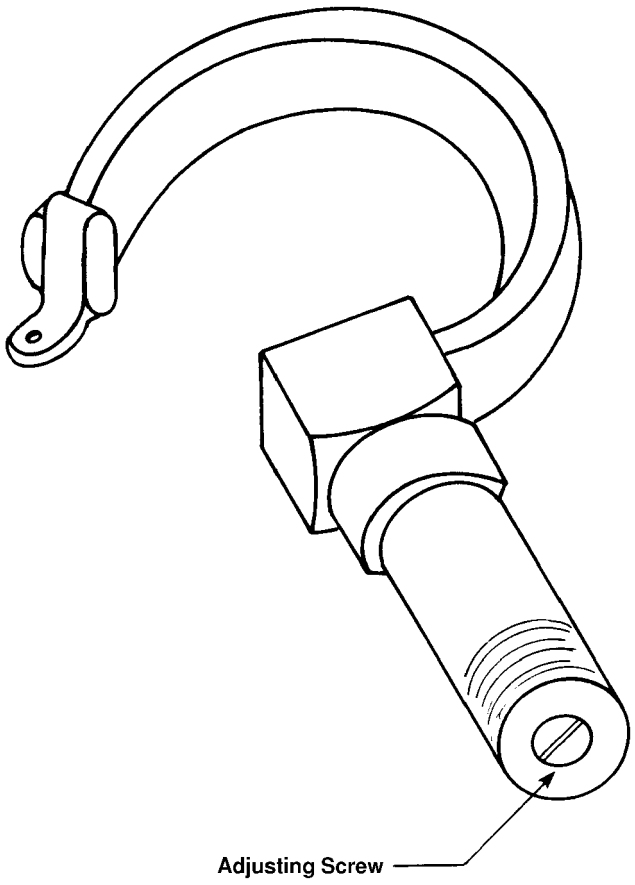

Figure 3: A Pressure Gauge Bourdon Assembly with Adjusting Screw

4.3. Pressure Gauges

4.3.1. General

1. A pressure gauge is a device that senses pressure and provides a visual representation of that pressure. Most pressure gauges have bourdon tube sensors. Vacuum gauges and low range gauges often use bellows sensors, while differential pressure gauges can use diaphragm, piston, or bellows sensors. The sensor type is usually dictated by the preferred manufacturer and the required range.

2. Pressure gauges shall be selected so that the expected operating pressure is in the center third of the gauge range. It is also important that the

highest pressure that shall ever be applied to the gauge be below the maximum reading. Usually, the gauge can be selected so that the maximum is above the set pressure of the system relief valve and that the normal pressure is in the readable range. If this is not possible, a pressure-limiting valve (see Section 4.5.4) can be used to protect the gauge from a potential overpressure.

3. Typical ranges for bourdon sensor pressure gauges are shown in Table 1; ranges for bellows sensor pressure gauges are shown in Table 2.

Table 1: Typical Bourdon Sensor Pressure Ranges (Courtesy of Dresser-Ashcroft)

Pressure (psi)		
Range	Figure Interval	Minor Graduation
0/15	1	0.2
0/30	5	0.5
0/60	5	1
0/100	10	1
0/160	20	2
0/200	20	2
0/300	30	5
0/400	50	5
0/600	50	10
0/800	100	10
0/1000	100	10
0/1500	200	20
0/2000	200	20
0/3000	300	50
0/5000	500	50
0/6000	1000	100
0/7500	1000	100
0/10,000	1000	100
0/15,000	2000	200
0/20,0001	2000	200

[1] Not available in $2^1/_2$ in and $3^1/_2$ in sizes

Table 1, Continued

Compound				
Range	Figure Interval		Minor Graduation	
	Mercury (in)	psi	Mercury (in)	psi
30 in Hg Vac/0/ 15 psi	5	3	1	0.5
30 in Hg Vac/0/ 30 psi	10	5	1	1
30 in Hg Vac/0/ 60 psi	10	10	2	1
30 in Hg Vac/0/ 100 psi	10	10	2	1
30 in Hg Vac/0/ 150 psi	10	20	5	2
30 in Hg Vac/0/ 300 psi	30	25	5	5

Combination					
Range		Figure Interval		Minor Graduations	
Inner Scale psi	Outer Scale ft water	psi	ft water	psi	ft water
$^0/_{15}$	$^0/_{34}$	3	5	0.5	1
$^0/_{30}$	$^0/_{70}$	5	10	0.5	1
$^0/_{60}$	$^0/_{140}$	5	20	1	2
$^0/_{100}$	$^0/_{230}$	10	20	1	5
$^0/_{160}$	$^0/_{370}$	20	50	2	5
$^0/_{200}$	$^0/_{460}$	20	50	5	5
$^0/_{300}$	$^0/_{690}$	25	50	5	10

Table 2: Typical bellows sensor pressure ranges (courtesy of Dresser-Ashcroft)

Double Arc						
Range		Dial Graduations				
Pressure		Inner Scale			Outer Scale	
Inner Scale	Outer Scale	Dial Arc(°)	Figure Interval	Minor Graduation	Figure Interval	Minor Graduation
in H_2O	oz/in^2					
$^0/_{10}$	$^0/_{6}$	180	1	0.5	1	0.25
$^0/_{15}$	$^0/_{9}$	180	3	0.5	1	0.25
$^0/_{20}$	$^0/_{12}$	180	2	1	1	0.25
$^0/_{30}$	$^0/_{18}$	216	5	1	1	0.5
$^0/_{40}$	$^0/_{24}$	270	5	1	3	0.5
$^0/_{60}$	$^0/_{35}$	270	5	1	5	1
$^0/_{80}$	$^0/_{45}$	270	10	1	5	1
$^0/_{100}$	$^0/_{57}$	270	10	1	5	1

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$^{0}/_{150}$	$^{0}/_{90}$	270	25	1	10	2
psi	in. Hg					
$^{0}/_{5}$	$^{0}/_{10}$	270	1	0.25	1	0.5
$^{0}/_{8}$	$^{0}/_{16}$	270	1	0.25	2	0.5
$^{0}/_{10}$	$^{0}/_{20}$	270	1	0.25	2	0.5
Vacuum						
in H_2O	mm Hg					
$^{10}/_{0}$	$^{18}/_{0}$	180	1	0.5	3	1
$^{15}/_{0}$	$^{28}/_{0}$	180	3	0.5	5	1
$^{20}/_{0}$	$^{37}/_{0}$	180	2	1	5	1
$^{30}/_{0}$	$^{56}/_{0}$	216	5	1	5	1
$^{40}/_{0}$	$^{75}/_{0}$	270	5	1	10	2
$^{60}/_{0}$	$^{110}/0$	270	5	1	10	2
$^{80}/_{0}$	$^{150}/_{0}$	270	10	1	20	5
$^{100}/_{0}$	$^{180}/_{0}$	270	10	1	20	5
$^{150}/_{0}$	$^{270}/_{0}$	270	25	1	20	5
in Hg	ft H_2O					
$^{10}/_{0}$	$^{11}/_{0}$	270	1	0.5	1	5
$^{15}/_{0}$	$^{17}/_{0}$	270	1	0.5	2	5
$^{20}/_{0}$	$^{23}/_{0}$	270	2	0.5	2	1

4. Pressure gauges are available in several sizes and types of mountings. The most common has a 4.5 in dial and bottom stem. This type usually mounts on a gauge valve and is self-supporting. The large dial is easily seen from a reasonable distance. The preferred gauge face is a white dial with black letters. Other styles are made for surface mounting on a plate or for flush mounting through a panel. The style is selected to suit the required mounting.

5. Local-mounted gauges are usually specified with 0.5 in NPT connections to provide adequate strength, while 0.25 in NPT connections are adequate for surface or panel-mounted gauges. Gauges with blowout backs are preferred so that a failure shall not injure a person looking at the gauge.

6. The wetted material shall be suitable for the process fluid. Type 316 stainless steel is suitable for nearly all hydrocarbon services, including sour gas. Gauges shall be ordered with a 316 stainless bourdon tube and socket for most process applications. Bronze can be used for air or water, but is not used for hydrocarbons. Most manufacturers publish a chart of recommended materials that cover many process fluids.

7. Pressure gauges are sometimes liquid-filled. This is particularly common offshore or in other corrosive environments to protect the gauge dial and movement from the atmosphere. The liquid fill also provides some pulsation or vibration dampening. Glycerine is the most common fill liquid. Silicone liquid is preferred in climates with minimum

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temperatures below -18°C (0°F) because of glycerine's high viscosity at low temperature. Either of these fill liquids creates an explosion hazard if exposed to oxidizing fluids such as oxygen, chlorine, hydrogen peroxide, or nitric acid. Consult the pressure gauge manufacturer for a suitable fill if in doubt.

8. The accuracy required depends on the intended use of the gauge. Most high-quality process gauges have ± 0.5 percent of full-scale accuracy. Economy lines of gauges usually have ± 1 percent accuracy, and test gauges usually have ± 0.25 percent accuracy.

9. A diaphragm seal shall be specified if the process fluid will jell at ambient temperatures and clog the gauge or if the fluid will corrode all available sensor materials. The seal shall have a flushing connection if the process fluid is viscous or dirty. The fill liquid is usually either glycerine or silicone.

10. Pressure gauges lose accuracy when exposed to hot fluids. When the process temperature is above approximately 82°C (180°F), a siphon shall be installed (see Section 4.5.2). If the process fluid will not condense at ambient temperature, the siphon can be filled with a suitable fluid such as ethylene glycol or glycerine. Siphons can be purchased with the gauge, or, if the gauge is surface-mounted, a loop can be bent into the connecting tubing.

11. Differential pressure gauges are useful when a pressure difference that is small compared to the static pressure must be measured. Differential pressure gauges differ from static-pressure gauges in that they have two pressure connections. The criteria for choosing differential pressure gauges are much the same as those for static pressure gauges. Differential gauges shall be installed with an equalizing valve so that they shall not be overranged while disconnecting. Figure 4 shows typical differential pressure gauge applications.

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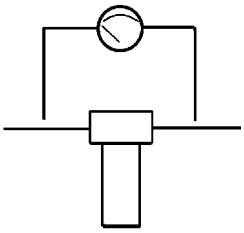
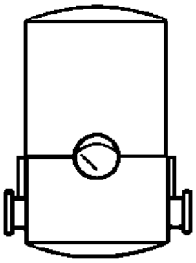
CARTRIDGE FILTERS



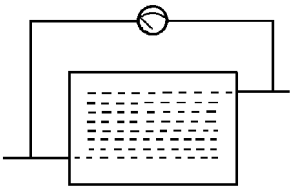
Differential Pressure Instruments monitor pressure loss across disposable cartridges and reusable screen cartridges. You know exactly when the cartridge needs replacing or cleaning, neither too soon (for economy and optimum use) nor too late (for system protection). Also used on desiccant and coalescing filters.

SELF-CLEANING FILTERS



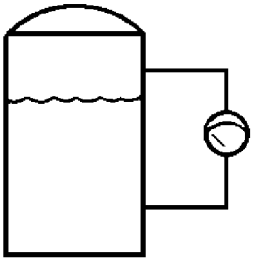
Delta P switches and indicating switches monitor the differential pressure increase across self-cleaning filters. When the set point is reached, the instrument automatically initiates the cleaning cycle. Can be used on backwash type filters and filters that index fresh filtering media.

HEAT EXCHANGERS



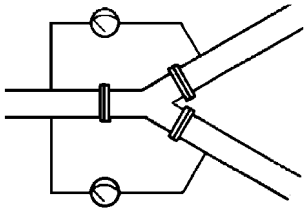
Instruments measure pressure loss as a function of scale built up within the heat exchanger tubes, which restricts flow; alert maintenance personnel before flow restrictions become critical.

LIQUID LEVEL



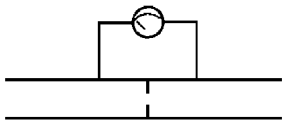
Delta P instruments monitor liquid level in storage tanks and vessels and are applicable for simple liquid level head pressure in non-pressurized tanks or liquid level in pressurized tanks based on differential pressure. Dials are graduated in units of liquid level or quantity.

BALANCING FLOW



Differential pressure instruments pinpoint reduction of flow rates in branch piping systems. Dials can be graduated in psid, flow rate, square root, or percentages.

FLOW RATE INDICATORS



Delta P instruments act as a continuous informer on flow rate to indicate normal, insufficient, or excessive flow rate conditions. Instruments are used in conjunction with conventional differential pressure generators, such as venturi, orifice plate, or pilot tube. Dials are graduated in units of flow based on differential pressure flow curves.

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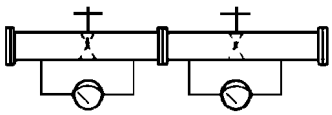
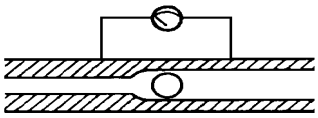
ADJUSTING FLOW RATE



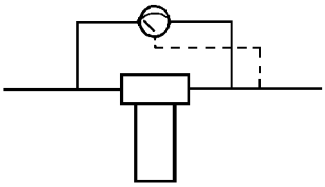
Differential pressure instruments can help establish flow rates through valves or other adjustable restrictions. On long runs of process piping, valves can be adjusted independently to compensate for pressure loss in piping and fittings to maintain uniform flow rates. These instruments are also useful for checking seals when a valve is closed.

DETECT REVERSE FLOW



Delta P instruments check back flow prevention devices to assure proper operation. Application of a delta P switch can control pump shut off.

FILTER BYPASS



Special instruments are available with a built-in bypass designed to open at a preset delta P level intended to supplement filter flow on cold starts or when filter is partially clogged (for low flow rates and low viscosity fluids only).

Figure 4: Typical Differential Pressure Gauge Applications

NOTES: Knowing the exact pressure loss helps to

1. eliminate premature servicing of equipment
2. avoid unscheduled down-time of costly equipment
3. detect abnormal system conditions

Examples are:

1. Pipeline flowrate balance/indication
2. Filters

12. The cost of a pressure gauge depends much more on dial size and accuracy than on sensor type. However, the cost variation can be severe. For example, a 1.5 in ± 5 percent gauge might cost $10 U.S., while a 0.01 percent helix sensor gauge can cost hundreds of dollars. The standard 4.5 in dial, direct-mounted gauge with 0.5 percent accuracy costs approximately $150 U.S. each. Additional specific information is presented in Section 5.13 of the Chilton Process Measurement Handbook.

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4.4. Pressure Switches

4.4.1. General

1. A pressure switch is a device that senses pressure and opens or closes a controlled element at a “set pressure”. The controlled element can be electric or pneumatic.

2. Most pressure switches trip at a pressure above atmospheric and are called “gauge pressure” switches or simply “pressure” switches. Switches can also be manufactured to trip at a pressure referenced to a complete vacuum; such switches are called “absolute pressure” switches. Those set to trip below atmospheric pressure are called “vacuum” switches, and those that can be set either above or below atmospheric are called “compound” switches.

3. Some switches are manufactured so that the trip point is factory-set, while others are field-adjustable. The factory-set varieties are less expensive, and they are a good choice for uses in which the exact trip point is not critical. Examples of this include electric interfaces for pneumatic systems such as fusible loops and pneumatic control panels.

4. Field-adjustable switches are usually needed for alarms and shutdowns that sense process pressure because their set pressures may need to be changed. The pressure ranges published in catalogs usually do not overlap much, if any, so it may be necessary to purchase a switch that is set near the limit of the published range. The actual range usually exceeds the published range somewhat, so this is not a severe problem.

5. Field-adjustable switches are manufactured with three basic types of adjustment. Most are called “internal set” because the adjustment is inside the housing. A cover must be opened or removed to adjust the set pressure. Others are called “external set”; these can be adjusted without opening the housing, but they are not calibrated. A third variety, called “dual set”, has a calibrated external adjustment.

6. Pressure switches are set to trip at a certain point with rising or falling pressure. When the pressure is returned to within the acceptable range, the switch does not reset at exactly the same point that it tripped. The difference between the trip point and the reset point is called “dead band” or “reset”. The switch shall be selected so that it can reset when normal conditions are restored. If the dead band is too large, it is possible to have a condition in which the high pressure shutdown switch will not reset before the low pressure shutdown switch trips. Dead band varies considerably on different types of switches and from manufacturer to manufacturer. Manufacturers' product description literature usually specifies dead band.

7. The wetted material of the switch shall be suitable for the process fluid. As with pressure gauges, type 316 stainless steel is usually the best

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choice for produced fluids. Manufacturers' published data shall be checked if there is any doubt.

4.4.2. Electric

1. Electric pressure switches are available in a wide variety of styles; choosing the correct one for a specific application involves several separate decisions. Switches are manufactured with a variety of pressure-sensing devices. The most frequently used, along with their characteristics, are tabulated in Table 3.

Table 3: Chart Comparing Various Types of Electric Pressure Switches (Courtesy of Barksdale Control Div.)

Characteristic	Switching Technology				
	Solid State	Diaphragm	Bourdon Tube	Piston	Dia-Seal Piston
Life (Typical)	10,000,000 cycles	1,000,000 cycles	1,000,000 cycles	2,500,000 cycles	1,000,000 cycles
Operating Range	1.5 to 10,000 psi	Vacuum to 150 psi	50 to 18,000 psi	15 to 20,000 psi	Vacuum to 1,000 psi
Accuracy	± 0.5% adjustable range	± 0.5% adjustable range	± 0.5% adjustable range	± 2.0% adjustable range	± 2.0% adjustable range
Resistance to Vibration	Excellent	Good	Good	Good	Good
Switch Differential Range	2 to 100% adjustable range	2 to 7% adjustable range	2 to 7% adjustable range	2 to 7% adjustable range	2 to 7% adjustable range
Operating Ambient Temperature Range	0° to 160°F	-65° to +165°F	-65° to +165°F	-20° to +165°F	-20° to +165°F
Proof Pressure	15,000 psi	300 psi	24,000 psi	20,000 psi	2,000 psi
Operating Indicators	2 LED's indicate over/under set point status	N/A	N/A	N/A	N/A

2. Most electric pressure switches have the mechanism isolated from the process fluid by a diaphragm; as a result, they are more tolerant of harsh conditions than pressure gauges and pressure pilots. A diaphragm material compatible with the process fluid shall be selected.

3. The electrical switch is usually either single-pole, double-throw (SPDT) or double-pole, double-throw (DPDT). The number of poles determines the number of separate circuits that can be controlled by the switch. DPDT switches are the preferred choice.

4. The cost of electric pressure switches can vary from $35 to $500 U.S. depending on specified features, (e.g., gold plated contacts, stainless steel body, etc.). The average price of pressure switches used in the petroleum industry is approximately $250 U.S.

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4.4.3. Pneumatic

Pneumatic pressure switches are generally the same as electric switches, but have a two- or three-way valve (instead of a contact block) as the controlled element. These switches have the same basic features as the electric switch. They are commonly used on small facilities where local control of individual skid units is employed. Costs of these switches are generally less than electric; the average is approximately $200 U.S.

4.4.4. Pressure Pilots

1. Most pressure pilots are either piston-actuated–known as stick pilots–or bourdon-tube-actuated pilots. Stick pilots are more often used on wellheads, and bourdon tube pilots are more often used on process equipment, although it is not uncommon to see exceptions.

2. Stick pilots are ruggedly constructed and can be readily disassembled for repair or cleaning. Typical stick pilot characteristics are shown in Table 4.

Table 4: Chart Showing Pressure Spans for Typical Stick Pilots (Courtesy of BWB Controls, Inc.)

Sensing Piston Assembly	Minimum (psi)	Approximate Reset (psi)	Maximum (psi)	Approximate Reset (psi)
No. $1^3/_8$ Piston	5	2	15	4
	15	4	50	7
	50	8	150	15
	150	15	200	20
No. $2^7/_8$ Piston	200	20	300	30
	300	30	600	60
No. $3^1/_2$ Piston	600	60	1000	100
	1000	100	1700	170
No. $4^3/_8$ Piston	1700	170	3000	300
No. $5^1/_4$ Piston	3000	300	6000	600

3. Bourdon tubes are not easily cleaned if clogged by congealed crude oil or wax. Both types are readily adjusted, but it is somewhat easier to adjust most of the bourdon tube models than stick pilots. Some models of bourdon tube pilots are equipped with pressure indicators and resemble pressure controllers.

4. Table 5 shows some typical bourdon tube pilot characteristics presented by one manufacturer. The bourdon tube rating is the safest high pressure that the pilot is designed to handle, and the set range is the pressure range over which high and low trip points may be set, typically 5 to 95 percent of the bourdon tube rating. The set point minimum change in pressure

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(set point P_{MIN}) is the limit on how close the high and low set points can be to each other; the trip-to-reset zone refers to the amount of pressure change from the set point that shall occur before the bourdon tube pilot responds; and nozzle/flapper and relay construction refer to the two common types of switching mechanisms used in bourdon tube pilots. For example, a bourdon tube pilot rated at 3450 kPa (500 psig) with a "nozzle/flapper" switching mechanism could have a low pressure set point as low as 172 kPa (25 psig) and a high pressure set point as high as 3277 kPa (475 psig). The high and low switch points could be as close as 690 kPa (100 psig) to one another and would have a deadband of 172 kPa (25 psig) around each switch point.

Table 5: Chart Showing Typical Bourdon Pilot Ranges (Courtesy of Fisher Controls)

Bourbon Tube Rating, bar	Set Range, psig	Set Point ΔP_{MIN} (Minimum Allowable Difference Between High and Low Settings)			Trip-to-Reset Zone (Dead Band)	
		Nozzle / Flapper Construction	Relay Construction		Nozzle / Flapper Construction	Relay Construction
			Single High-Low Unit	High Only/Low Only Pair		
100	5 to 95	20	10	3.0	5.0	1.5
250	13 to 237	50	25	7.5	12.5	3.8
500	25 to 475	100	50	15	25	7.5
1000	50 to 950	200	100	30	50	15
1500	75 to 1425	300	150	45	75	23
2500	125 to 2375	500	250	75	125	38
5000	250 to 4750	1000	750	150	250	75
7500	375 to 7125	1500	1125	225	375	113

Bourbon Tube Rating, bar	Set Range,* bar	Set Point ΔP_{MIN} (Minimum Allowable Difference Between High and Low Settings)			Trip-to-Reset Zone	
		Nozzle / Flapper Construction	Relay Construction		Nozzle / Flapper Construction	Relay Construction
			Single High-Low Unit	High Only/Low Only Pair		
7	0.35 to 6.65	1.4	0.7	0.21	0.35	0.11
17	0.85 to 16.15	3.5	1.7	0.51	0.85	0.26
35	1.75 to 33.25	7	3.5	1.05	1.75	0.53
70	3.5 to 66.5	14	7	2.1	3.5	1.1
100	5 to 95	20	10	3.0	5.0	1.5
170	8.5 to 161.5	34	17	5.1	8.5	2.6
350	17.5 to 332.5	70	35	10.5	17.5	5.3
500	25 to 475	100	50	15.0	25.0	7.5
*Ratings indicated on bourdon tube and set range on front panel are in kPa (1 bar = 100 kPa)						

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Table 5, Conclusion

Bourdon Tube Rating		Maximum Allowable Emergency Process Pressure			
Psig	Bar *	4130 Steel Alloy Bourdon Tubes		316 Stainless Steel Bourdon Tubes	
		Psig	Bar*	Psig	Bar*
100	7	200	14	200	14
250	17	500	34	500	34
500	35	1000	70	1000	70
1000	70	2000	140	2000	140
1500	100	3000	200	3000	200
2500	170	3750	280	5000	340
5000	350			5000	300
7500	500			7500	500
* Ratings indicated on bourdon tube and set range on front panel are in kPa 1 bar = 100 kPa					

5. Pneumatic devices tend to have an even larger dead band than electric devices because more movement is required for actuation. Consult the manufacturer's literature to be sure that the specified dead band is acceptable for the specific application.

6. Pressure pilot wetted materials for hydrocarbon service are usually type 316 stainless steel. Stick pilots have o-rings which contact the process and are usually of Viton. Buna-N, neoprene, and other o-ring materials can be used if Viton is not suitable for the fluid. Viton is usually preferred for crude oil and sweet gas because it is resistant to aliphatic and aromatic hydrocarbons. Buna-N is better for gas with carbon dioxide, while neoprene is better for sour gas. If corrosion inhibitors or other chemicals are added to the stream, consult the chemical supplier for assistance in elastomer selection.

7. Spring-loaded piston sensors are used for both pneumatic and electric pressure switches. These devices are usually called pressure switches when they are manufactured by companies that fit either electric or pneumatic output modules to their sensors. Companies that manufacture devices which are only pneumatic usually refer to their products as pressure sensors or pressure pilots. Heavy-duty pressure sensors such as the one shown in Figure 5 are often called “stick pilots”.

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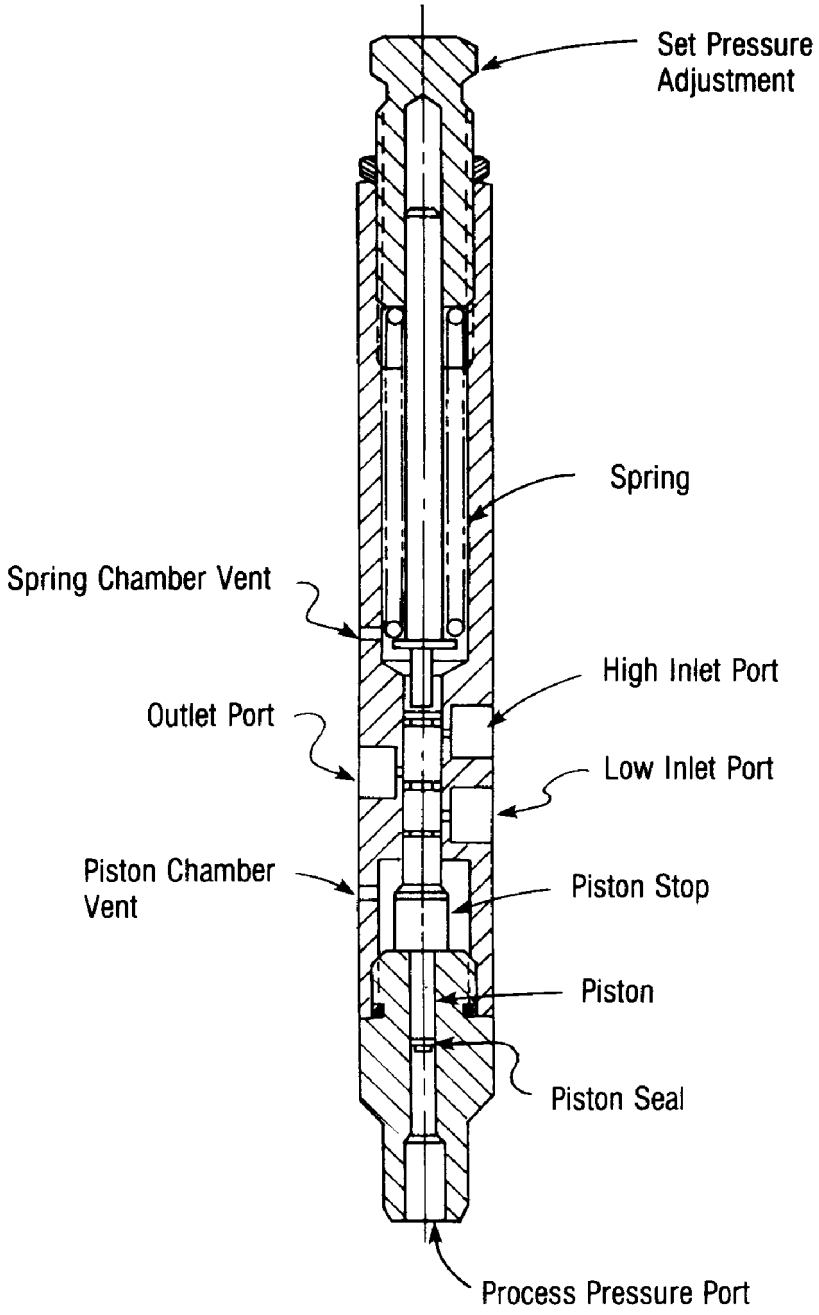

Figure 5: A Diagram of a Typical Stick Pilot (Courtesy of WKM)

8. Stick pilots are manufactured so that they can serve as either a high pressure sensor or low pressure sensor as required. The terms “high pressure pilot” and “low pressure pilot” refer to the way the sensor is connected; the terms do not denote two different devices.

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9. Figure 5 shows a stick pilot with no process pressure applied. When it is installed as a high pressure pilot, instrument air is connected to the high-inlet port, and the shutdown system is connected to the outlet port. The low-inlet port is left open. Notice that the high-inlet port and the outlet port are connected through the pilot body and isolated from the low-inlet port and the spring chamber by o-rings. The set pressure adjustment compresses the spring so that the piston does not move until the process pressure rises to the set pressure. When the set pressure is exceeded, the middle o-ring moves past the outlet port and connects it to the low-inlet port. The air from the high-inlet port is blocked by the o-ring, and the air in the shutdown system vents out the low-inlet port. The spring chamber and piston chamber vents keep their respective chambers at atmospheric pressure so that small leaks do not affect the set pressure.

10. A stick pilot installed as a low pressure pilot has the instrument air connected to the low-inlet port and the shutdown system connected to the outlet port. The high-inlet port shall be left open. The shutdown system is vented when the process pressure is below the set point and pressured when it is above the set point.

11. Stick pilots are available for set pressures from 30 to 66,000 kPa (5 to 10,000 psig). They are machined from bar-stock and are quite rugged. Repair usually consists of cleaning and replacement of o-rings and seals; this job can be done by most operations personnel. Stick pilots are suitable for pressure sensors throughout pneumatic control systems. Wellhead safety systems usually use them because of their ruggedness. Stick pilots are somewhat more expensive than bourdon-actuated pilots or pneumatic pressure switches.

4.5. Pressure Transmitters

4.5.1.

Pressure transmitters are used to interface control, indication, and data systems with the process. They are also used when several devices are to be operated from a single measurement or when elevated zero is required. The output is usually 4 to 20 mA for electronic transmitters or 20 to 100 kPa (3 to 15 psig) for pneumatic transmitters. Other signals can be used if required by the receiver, but these are the most common and shall be used if possible. Typical pressure transmitter data are shown by the following functional specifications:

Service: Liquid, gas or vapor.

Ranges:

1. $0\text{-}{}^{5}/_{30}$ in H_2O
2. $0\text{-}{}^{25}/_{150}$ in H_2O

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3. $0\text{-}^{125}/_{750}$ in H_2O

Outputs: 4 to 20 mADC

Power Supply:

1. External power supply required
2. 4 to 20 mADC: Transmitter operates on 12 to 45 VDC with no load.

4.5.2.

The use of pneumatic transmitters is decreasing; however, a number of manufacturers still make them for the replacement market, and some new installations are still being made. Pneumatic transmission may be advantageous when existing equipment is pneumatic and operating personnel are familiar with pneumatics.

4.5.3.

The sensing element's wetted parts shall be compatible with the process fluids. As with pressure gauges and pressure controllers, type 316 stainless steel is the most universally acceptable material for produced fluids. Most manufacturers provide a compatibility chart with their recommendations. The transmitter body is usually carbon steel or stainless steel. Carbon steel is adequate for most applications. Stainless steel bodies are sometimes needed if the environment is severe.

4.5.4.

Pressure transmitters are available in a variety of ranges. The ranges available vary sufficiently from one manufacturer to another to make it necessary to consult manufacturers' literature before selection.

4.5.5.

Several companies offer microprocessor-based pressure transmitters, sometimes called “smart transmitters”. These transmitters can be remotely programmed and/or calibrated for any desired range, either by the main process computer or by a special programmer. These transmitters are usually used in Distributed Control System (DCS) applications.

4.6. Pressure Controllers

4.6.1.

A pressure controller is a device that senses the pressure in the process and develops an output that controls a device to regulate that pressure. The sensing element is one of the various types discussed in Section 3,

"Principles of Operation". The control device, or end element, is usually a pneumatic control valve. The controller output is usually either a 20 to 100 or 40 to 200 kPa (3 to 15 or 6 to 30 psig) pneumatic signal. In this case of electronic controllers, the output is 4 to 20 or 10 to 50 mA.

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Process Measurement Instrumentation

MP 32-P-02

August 1998

Scope

This Mobil Engineering Practice (MEP) covers the basic requirements for the design, procurement, installation and testing of flow, level, pressure and temperature instruments. It is based on the practices specified in API RP 551, Process Measurement Instrumentation.

Version 0

Table of Contents

Scope **1**

Table of Tables **4**

1. References **5**

1.1. MEPS–Mobil Engineering Practices 5

1.2. Mobil Data Sheets 5

1.3. API–American Petroleum Institute 7

1.4. ISO–International Standards Organization 7

1.5. ASME–American Society of Mechanical Engineers 7

2. Flow **8**

2.1. General 8

2.2. Flow Element Selection 8

2.3. Flowmeters 9

2.4. Orifice Plate Design 11

2.5. Meter Runs 13

2.6. Differential Pressure (dP) Flowmeters 15

2.7. dP Flowmeter Installation 17

2.8. Miscellaneous Flow Devices 18

2.9. Calibration and Testing 18

2.10. Electronic Flow Computers 19

3. Level **20**

4. Pressure **20**

5. Temperature **21**

6. Modifications to API RP 551 ..... **21**

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Modifications to API RP 551 Section 3: Level 21

Modifications to API RP 551 Section 4: Pressure 26

Modifications to API RP 551 Section 5: Temperature 28

Appendix: Tables 33

Table of Tables

Table 1: Minimum Ratings for Gauge Glasses and Gauge Cocks 23

Table A–1: Orientation Table for Flow Sensors.....33

Table A–2: Flowmeter Selection Table.....40

Table A–3: Orientation Table for Level Detectors 45

Table A–4: Level Sensor Selection Guide.....51

Table A–5: Thermocouple Comparison Table 56

Table A–6: Differences in Color Codes Between the U.S. and IEC.....58

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1. References

The following publications form a part of this Practice. Unless otherwise specified herein, use the latest edition.

1.1. MEPS–Mobil Engineering Practices

MP 01-P-02	Structures & Equip.-External Loading Design Basis
MP 12-P-01	Pressure Vessels-Design & Fabrication
MP 16-P-01	Piping-General Design
MP 16-P-13	Use of Composite Pipe in Offshore Firewater Service
MP 16-P-30A	Piping - Materials and Service Classifications (M&R)
MP 16-P-31A	Piping-Classifications-(E&P, On/Offshore)
MP 16-P-40	Piping-Fabrication, Erection, Inspection, & Testing
MP 32-P-01	General Requirements for Instrumentation
MP 32-P-19	Instrumentation Piping and Tubing Fittings
MP 32-P-21	Wiring for Instrumentation and Digital Systems
MP 33-P-25	Electrical - Lighting, Receptacles and Associated Equipment

1.2. Mobil Data Sheets

Mobil Data Sheets	Mobil Data Sheet Home Page
T3202C01	Process Measurement Instrumentation - Level Gauge Glasses & Cocks - Customary Units
T3202M01	Process Measurement Instrumentation - Level Gauge Glasses & Cocks - Customary Units
T3202C02	Process Measurement Instrumentation - Displacer or Float Instruments - Customary Units
T3202M02	Process Measurement Instrumentation - Displacer or Float Instruments - Customary Units
T3202C03	Process Measurement Instrumentation - Displacer or Float Level Switches - Customary Units
T3202M03	Process Measurement Instrumentation - Displacer or Float Level Switches - Metric Units

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T3202C04	Process Measurement Instrumentation - Differential Pressure Transmitters - Customary Units
T3202M04	Process Measurement Instrumentation - Differential Pressure Transmitters - Metric Units
T3202C05	Process Measurement Instrumentation - Capacitance Instruments - Customary Units
T3202M05	Process Measurement Instrumentation - Capacitance Instruments - Metric Units
T3202C06	Process Measurement Instrumentation - Sonic Instruments - Customary Units
T3202M06	Process Measurement Instrumentation - Sonic Instruments - Metric Units
T3202C07	Process Measurement Instrumentation - Indicating Thermometers - Customary Units
T3202M07	Process Measurement Instrumentation - Indicating Thermometers - Metric Units
T3202C08	Process Measurement Instrumentation - Thermowells - Customary Units
T3202M08	Process Measurement Instrumentation - Thermowells - Metric Units
T3202C09	Process Measurement Instrumentation - Thermocouples - Customary Units
T3202M09	Process Measurement Instrumentation - Thermocouples - Metric Units
T3202C10	Process Measurement Instrumentation - Resistance Temperature Detectors - Customary Units
T3202M10	Process Measurement Instrumentation - Resistance Temperature Detectors - Metric Units
T3202C11	Process Measurement Instrumentation - Temperature Switches - Customary Units
T3202M11	Process Measurement Instrumentation - Temperature Switches - Metric Units
T3202C12	Process Measurement Instrumentation - Pressure Gauges - Customary Units
T3202M12	Process Measurement Instrumentation - Pressure Gauges - Metric Units
T3202C13	Process Measurement Instrumentation - Pressure Transmitters - Customary Units
T3202M13	Process Measurement Instrumentation - Pressure Transmitters - Metric Units
T3202C14	Process Measurement Instrumentation - Direct Coupled - Customary Units
T3202M14	Process Measurement Instrumentation - Pressure Switches - Metric Units
T3202C15	Process Measurement Instrumentation - Pressure Switches - Customary Units
T3202M15	Process Measurement Instrumentation - Direct Coupled - Metric Units

D3202C01	Process Measurement Instrumentation - Documentation Requirements Sheet
I3202C01	Process Measurement Instrumentation - Inspection & Testing Requirements Sheet

1.3. API–American Petroleum Institute

API MPMS 14.3.3	Manual of Petroleum Measurement Standards Chapter 14 - Natural Gas Fluids Measurement Section 3 - Concentric, Square-Edged Orifice Meters Part 3 - Natural Gas Applications Third Edition; Errata - 1994
API RP 551	Process Measurement Instrumentation First Edition

1.4. ISO–International Standards Organization

ISO 5167-1	Measurement of Fluid Flow by Means of Pressure Differential Devices - Part 1: Orifice Plates, Nozzles and Venturi Tubes Inserted in Circular Cross-Section Conduits Running Full First Edition

1.5. ASME–American Society of Mechanical Engineers

ASME PTC 19.3	Part 3: Temperature Measurement Instruments and Apparatus (Performance Test Codes) R(1986)
ASME PTC 19.5	Application Part II of Fluid Meters Sixth Edition 1971 (Interim Supplement 19.5 on Instruments and Apparatus) (Performance Test Codes)
ASME SEC IX	BPVC SECTION IX Qualification Standard for Welding and Brazing Procedures, Welders, Brazers, and Welding and Brazing Operators Addenda - 1995; Addenda - 1996; Interfiled (Boiler and Pressure Vessel Codes)

2. Flow

2.1. General

- The design, procurement, installation and testing of flow, level, pressure and temperature instruments shall be in accordance with requirements of this MEP, unless superceded by more stringent local regulations.
- The references and requirements of MP 32-P-01 shall apply to this Practice. Refer to Tables A–1 and A–4 of Appendix A of this MEP for more information.
- The term "accounting service" shall be defined as "flow metering service for the purpose of measuring product yield." Accounting services and methods of flow measurement therefore shall be subject to approval.
- Products that are measured volumetrically and shipped outside the plant facility to second or third parties shall require custody transfer meter and proving systems.
- For imported products, a source meter(s) and proving system or a secondary custody transfer metering system to verify volumetric flow shall be required, subject to approval.
- Critical gas flows shall require temperature and pressure compensation for corrected volumetric flow (for example, anti-surge control for gas compressors).
- Orifice plates are the most widely used devices on gas service for accounting and fiscal metering. Turbine and positive displacement meters are typically used in liquid fiscal service. An alternative that could prove advantageous may be proposed for approval.
- Subject to approval, use manufacturer installation instructions when the primary element is not covered by industry standards (API, ANSI, ISO, etc.).

2.2. Flow Element Selection

Concentric orifice plates shall be the first choice for primary elements.

2.2.1. Flow Element Types

The following flow measuring devices have a summary description in API RP 551, Section 2.3:

- Orifice
- Force or target flowmeter
- Flow nozzle

- Turbine flowmeter
- Venturi tube
- Electromagnetic flowmeter
- Flow tube
- Positive displacement meter
- Pitot tube
- Vortex shedding meter
- Elbow taps
- Sonic flowmeter
- Variable area flowmeter
- Mass flowmeter (coriolis type)

The flow measuring devices listed below and other devices developed for special applications may be used with approval after those devices listed above are shown to be not applicable:

- Swirl
- V-Cone flowmeter
- Thermal
- Dall tube

2.3. Flowmeters

2.3.1. Liquid Service

1. In-line turbine meters or positive displacement meters shall be used for custody transfer and accounting services unless otherwise defined in the project specifications.
2. Variable area meters shall be used for non-accounting flow, where economical local reading is required for applications with low flowrates, volatile service and viscous streams.
3. Positive displacement meters shall be used for custody transfer and meter proving systems. Built-in mechanical type temperature compensators shall not be used; a separate temperature transmitter shall be added to flow systems requiring compensation (e.g., custody transfer and accounting).

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4. Target meters shall be used only for highly viscous fluids or in cases of gas service defined in a licensed process package.
5. Magnetic flowmeters are to be used only in electrically conductive liquid services, such as seawater and certain acids.
6. Vortex shedding meters shall be used where gas cannot be eliminated from a liquid stream or in lieu of an orifice plate where high turndown is required.
7. An on-line turbine meter system shall be used for test separator oil or condensate flow metering. The same system is preferred for test separator water metering, but possible erosion problems shall be addressed. In either case, connections for meter proving using a master meter, conventional prover loop or small volume prover (SVP) shall be provided.
8. All in-line turbine meters installed in accounting or fiscal meter stations shall have dual sensors.
9. Mass flowmeters (Coriolis type) shall be used for extremely viscous fluids or where mass flow measurement is required.

2.3.2. Gas Service

- Orifice meters or other devices requiring turbulent flow shall not be used in streams with low velocities (Reynolds number less than 3150).
- Orifice meters shall not be used in process streams where the pressure loss would affect the process or adequate pressure drop is not available for accurate measurement.
- Orifice meters with multiple transmitters or other methods shall be used where rangeability exceeds 3:1.
- Pitot tubes and elbow taps shall be used where low accuracies are acceptable and significant cost savings are achieved.
- A concentric plate shall be used when measuring gas with an orifice meter.
- The selection of a flow metering device, applied to compressor suction or discharge, shall be carefully considered. A low pressure drop flow nozzle, such as the Dall tube, shall be used for this service when the pressure drop is to be kept minimal.

2.3.3. Installation

Flowmeter installations shall be in accordance with API RP 551, Section 2. Flowmeters are primary elements in process control loops and shall be installed upstream of corresponding control valves.

2.3.3.1. Piping

- Impulse piping runs to bellows-type (non-negligible volumetric displacement) meters shall not exceed 6 m (20 ft), with a minimum downward slope of 83 mm/m (1 in/ft).
- Piping shall slope downward toward the meter for liquid service and upward toward the meter in gaseous service.
- Type 316 stainless steel fittings and Type 316 or better stainless steel annealed seamless tubing is preferred as a minimum.
- Other materials can be used accordingly as required by the process and piping specifications.

2.3.3.2. Flow Indicators

Local indicating or recording flowmeters used in conjunction with a hand control valve shall be installed so that the flow is easily readable from the control valve location.

2.3.3.3. Sealing

- Differential pressure meters of the diaphragm type (negligible volumetric displacement) can be sealed without the use of seal pots or chambers.
- Use of seals shall require approval and shall conform to the following:
  - Seal chambers shall be used for bellows-type flowmeters used in wet gas service, in corrosive, viscous, unstable services or where fluids may be subject to freezing.
  - Condensate chambers shall be used for bellows-type meters in steam service.
  - Seals and seal chambers, when required, shall be in accordance with MP 32-P-01.

2.3.3.4. Purge Systems

Purge systems of the constant-flow type shall be provided when orifice or pressure tap plugging is anticipated. The type of purge media and connections shall be in accordance with MP 32-P-01 or project specifications.

2.4. Orifice Plate Design

- Orifice bores shall be sized to provide a reading between 6 and 8 on a 0–10 square-root scale when the flow is at normal design rate. The beta ratio (ratio of orifice bore to pipe internal diameter) shall not be greater than 0.70 nor less than 0.20.
- The minimum orifice flange size shall be 50 mm (2 in).

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- Standard differential pressure ranges shall be as specified in Section 2.6.2 of this MEP.
- Plates shall be bored to the nearest 3 mm ($^1/_8$ in) for bores 102 mm (4 in) and smaller and to the nearest 6 mm ($^1/_4$ in) for bores greater than 102 mm (4 in). Subject to approval, plates may be bored for odd sizes in order to obtain even coefficients.

2.4.1. Coefficient Calculation Methods

Orifice and flow coefficient calculation methods shall be based on the job specifications and the following sources, as applicable:

- INSTRUCALC latest version of flow element sizing computer program (Gulf Publishing, Houston, TX)
- Flow Measurement Engineering Handbook, 2nd Ed., by R.W. Miller
- API MPMS 14.3.3–only for gas metering applications
- ISO 5167-1

Other methods of flowmeter calculation (including software) may be used subject to approval.

2.4.2. Fabrication

- Orifice plate fabrication shall include requirements of API RP 551, Section 2.
- Weep holes shall not be provided, unless noted in the job specifications.
- For ring joint construction, the plate holder shall be a handle-type oval ring of pipe specification material.
- All orifice plates shall be purchased from approved suppliers.

2.4.2.1. Handle Requirements

- All orifice plates shall have handles with the following information stamped on the upstream side:
  - Upstream
  - Orifice size (bore)
  - Instrument Tag Number
  - Inside diameter (ID) of the pipe
  - Material specification
  - Bore type (concentric, eccentric, segmental, sharp edge or quadrant edge)

- Letters shall be no less than 3 mm ($^3/_4$ in) high and shall be legible when installed.
- Handles shall extend sufficiently beyond the flange insulation to permit information to be read without removing the insulation. For plates fitted inside of fittings, this information shall be stamped on the upstream side of the plate but not exposed to the flow stream.
- In order to verify that orifice plates are correctly installed, each handle shall have a notch cut from the left-hand corner, viewed from the upstream side of the orifice. The notch size shall be approximately 6 x 6 mm ($^1/_4$ x $^1/_4$ in).

2.4.2.2. Metal Seal Rings

- Metal seal rings shall be used in orifice fittings.

2.5. Meter Runs

2.5.1. Fabrication

To ensure proper fabrication, meter runs shall be purchased from an approved fabricator.

- Matched/mated raised-face weld neck orifice flanges shall have a minimum Class 300 rating and shall have two taps per flange.
- Unused taps shall be plugged with solid plugs and back welded.
- If the runs are galvanized, they shall be galvanized centrifugally and not hot dipped.
- Upstream and downstream pipe lengths shall be selected on the basis of a beta ratio of 0.70 and shall conform to the requirements of ISO 5167-1 and API RP 551 unless local requirements indicate otherwise.

Fabrication of meter runs is usually done at a qualified manufacturer's plant facility or at the jobsite. Final inspection shall be approved. In such cases, quality control, inspection, documentation and selection of material and fabrication shall be the responsibility of the qualified meter run fabricator.

2.5.2. Use of Meter Runs

Meter runs shall be used for all continuous process flow applications. For some intermittent flow applications, where measurement errors are tolerable and the flow measurement is simply an approximation, a prefabricated meter run may not be required.

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2.5.3. Space Limitations

Space-limited applications may require specialized design arrangements of piping and equipment. Examples may include preassembled modules, packaged units and skid-mounted equipment on vehicles and ships. In such cases, where adherence to ISO 5167-1 at 0.70 beta ratio causes impractical piping/equipment design or severe cost penalties, the following steps (in order of priority shown) may be taken to solve the problem:

1. Apply ISO 5167-1 at the actual beta ratio rather than at a ratio of 0.70.
2. Use the alternate (bracketed) values in the ISO 5167-1 tables. These values produce an added uncertainty of 0.5 percent to the measurement accuracy. For noncustody transfer applications this may be acceptable. The use of values given in API RP 551, Section 2 shall require approval.
3. Straightening vanes shall be used only with approval.
4. Install another type of flow measuring device that can produce the required degree of accuracy when installed within the design constraints of the particular facility. If no practical and acceptable flow measuring device can be found for the particular facility, the measuring system shall not be considered reliable and shall be used simply to establish that flow is occurring at an indeterminate rate.

2.5.4. Piping

Piping shall be in accordance with MEP Series 16 (see Section 1.1 of this MEP for specific MEP numbers).

2.5.5. Inspection and Maintenance

- Primary flow measuring elements shall have flanged connections to permit easy removal for inspection and maintenance. Meter runs shall have weld neck flanges on the downstream end to facilitate inspection of the internal surface.
- Exceptions to this rule are the approval of another location or a flange conveniently located for the purpose. Refer to ASME PTC 19.5, Fluid Meters (Part Two, Figure II-4). The upstream flange shown in the ASME figure is optional.

2.5.6. Taps/Couplings

- Orifice flange taps shall be on the horizontal flange centerlines to accommodate the use of redundant taps and meters off the same meter run. If clearance limits the use of horizontal centerline taps, then taps above 45 degrees for gas and vapor service and below 45 degrees for liquid service may be used, subject to approval.
- The use of pipe taps, radius taps or vena contracta taps shall be restricted to meters used for normal operations.

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- In the use of radius taps, special care shall be taken to ensure the tapping points are clear of slag and other materials.
- The sensing point for static pressure shall be the downstream orifice tap.
- One 25 mm (1 in) coupling shall be provided on the downstream section, if temperature or pressure measurement is required and if there are no other suitable taps available in the metering run system. This coupling shall be located on the top of the pipe and on vertical centerlines. The centerline of the coupling shall be at least six pipe diameters from the face of the downstream orifice flange.
- For all custody transfer meter applications, flange taps shall be used unless otherwise approved.

2.5.7. Accounting Service Meter Run

Each section of the accounting service meter run shall have its average ID stamped on a stainless steel name plate welded to the section. Meter run calibration and copies of all data taken to determine this average value shall be witnessed and reviewed.

2.5.8. Vertical/Horizontal Runs

Meter runs installed for vertical flows shall be upward for liquids and downward for gas and steam containing condensate and vapor. If this is not practical, meter runs installed horizontally for liquid service shall have the downstream line turning vertically upward at least the meter run downstream length.

Meter runs for gas service installed horizontally shall have the downstream line turning vertically downward for at least the meter run downstream length.

Bolt holes of all flanges for horizontal meter runs shall straddle the vertical centerline of the assembled installed tube. When bolted together, the meter runs shall be straight.

2.5.9. Shipping

When shipped from the manufacturer, the meter runs shall have steel plate covers between the flanges and the wood cover. Both covers shall be bolted on the inlet and outlet flanges (if the meter run is shipped by itself) in order to prevent internal damage by mishandling.

2.6. Differential Pressure (dP) Flowmeters

Differential pressure instruments shall withstand pressures equal to 1.5 times full-line pressure without zero or calibration changes. Instrument body materials shall be 316 stainless steel as a minimum and be consistent with or exceed the piping material

specification. No instrument damage shall result if full-line pressure is connected to the low-pressure side of the transmitter.

The use of on-line gas density metering compensation for accounting and fiscal services is not recommended and shall only be used if mandated by local or contractual requirements, as indicated in the job specifications. For operational flow metering service, the application of on-line pressure and temperature compensation is considered sufficient. These accounting services shall be provided with integrators or flow computers located in the control room, as indicated in the job specifications.

2.6.1. Remote Locations

For accounting or fiscal flow measurement service in remote locations where electric service and a conditioned air room is not available, the type of integrating/computing hardware used shall be in accordance with the job specifications. The preferred type, where applicable, is the self- contained, solar-powered electronic flow computer. Other integrating units for these remote applications, such as mechanical integrators are subject to approval.

2.6.2. dP Ranges

A differential pressure range of 25 kPa (100 inches of water), dry calibration, shall be used for liquid flowmeters, unless otherwise specified. For gas, steam or vapor service, meters shall have the following ranges unless otherwise specified in the job specifications:

1. For static pressures less than 35 kPa gauge (5 psig), the range in inches of water shall not exceed one-seventh of the static gauge pressure.
2. For static pressures between 35–240 kPa gauge (5–35 psig), the range shall be 5kPa (20 in) of water.
3. For static pressure between 240–585 kPa gauge (35–85 psig), the range shall be 12.7kPa (50 in) of water.
4. For static pressures above 585 kPa gauge (85 psig), the range shall be 25.0kPa (100 in) of water.

2.6.3. Bellows-Type Meters

Bellows-type dP meters shall be equipped with over-range checks and used for the following services:

1. Local indicators or recorders.
2. Transmitters for integrators only.
3. Pulsating flow, where internal damping could be advantageous. For accounting service in remote locations where electric power or instrument air is not available, bellows-type recording meters, equipped with 0–10 square-root charts and mechanical integrators may be used.

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4. Impulse piping runs to bellows-type meters shall not exceed 6 m (20 ft), with a minimum downward slope of 83 mm/m (1 in/ft).

2.6.4. Transmitters

- Diaphragm dP transmitters with negligible volumetric displacement shall be used. Mercury shall not be used.
- Transmitters shall be close coupled to the orifice flow elements if access for maintenance exists from grade or fixed platform (as shown in API RP 551, Section 2, Figure 3). Otherwise, the dP transmitter shall be mounted on a NPS 2 instrument stand with a five-valve manifold.
- Impulse line length may be extended to a maximum of 6 m (20 ft) for remote transmitters.
- In severe vibrating conditions, the meter shall be remotely mounted.

2.7. dP Flowmeter Installation

Installations for operational purposes shall be in accordance with API RP 551, Section 2. Requirements for accounting and fiscal metering shall be as identified in the job specifications and as mandated by local regulations.

Flowmeters shall be provided with vent and/or drain valves in the process leads. Valves shall be piped to a safe location.

2.7.1. Seal Installation

Installation of seals requires approval and shall conform to the following:

1. Seal chambers shall be used for bellows-type flowmeters in wet gas, corrosive, viscous, unstable or freezing fluid services.
2. Condensate chambers shall be used for bellows-type meters in steam services.
3. Differential pressure meters of the diaphragm type shall normally be sealed without using pots or chambers.

2.7.2. Purge Systems

Purge systems of the constant-flow type shall be provided when orifice or pressure tap plugging is expected. The type of purge medium and connections shall be in accordance with the job specifications.

Differential pressure transmitters in cryogenic applications (temperatures below -30°C [-22°F]) shall be self-draining (transmitters shall be elevated above tapping points). Otherwise, approval to use a gas purge or light thermal insulation shall be required.

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2.8. Miscellaneous Flow Devices

Non-orifice metering devices shall be considered if the following conditions exist:

1. Low flow
2. Flow measurement for minimal pressure drop and/or low static pressure
3. A greater than 10:1 rangeability is needed and cannot be achieved with dual dP cells
4. Flow varies rapidly and randomly, negating the use of orifice changing
5. A lower accuracy is acceptable

If any of the above conditions apply, the following devices shall be considered subject to approval:

1. Vortex shedding
2. Ultrasonic
3. Thermal
4. Annubar or average Pitot tube elements
5. Rotameters
6. Magnetic
7. Dall tube
8. Turbine meters (including insertion turbine meters)
9. Force or target flowmeters
10. Mass flowmeter (Coriolis type)

2.9. Calibration and Testing

Meter runs in conformance with Section 2.5 of this MEP do not require further calibration, provided the flow medium specifications and rate remain within the bounds of the original design criteria. Low-flow orifice systems using meter run diameters less than 50 mm (2 in) shall require flow laboratory calibration, since the pipe roughness factor cannot be calculated accurately for the smaller-diameter pipe.

Subject to approval, either a portable or a permanently installed meter prover may be used to verify meter calibration.

Where calibration is required, the method shall be an industry recognized method. It shall conform to the local mandatory and contractual requirements, which shall be as identified in the job specifications.

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In fiscal gas flow metering with line pressure exceeding 10,340 kPa (1500 psia), calibration at line pressure shall be conducted to establish the effect of static pressure alignment drift on the accuracy of the differential pressure meter.

2.10. Electronic Flow Computers (EFC)

Electronic Flow Computers (EFC) shall meet or exceed the following general requirements, unless otherwise established by local regulations or contractual agreements:

1. Separate static pressure and temperature devices shall be used for each meter run. A common static pressure or temperature point may be used, subject to approval. Dual dP devices shall be used to cover the entire flow range and to meet the accuracy requirements.

2. EFCs shall be intrinsically safe if locally mounted. For offshore use, all locally mounted EFCs shall be certified for Class I, Division II. Exceptions shall be subject to approval depending on hazardous area classification.

3. The EFC shall have the following minimum audit requirements:

   a) Store internally a minimum of 35 days of data. Data shall include, but not be limited to, static pressure, differential pressure, temperature, calculated flow rate, yesterday's volume, today's volume and other site-specified information.

   b) Keep an event log of up to 100 items, showing all actions taken that will affect the audit trail. The event log shall keep records showing the time and security code used to access the flow computer, alarms and their acknowledgment, calibrations performed and any basic data changes made by anyone accessing the computer.

   c) Keep a file containing the basic data entered into the computer by the user, which will be used in the flow calculation. The "read only memory" where these data are stored shall have a battery backup to prevent data loss due to main power failure.

6. The EFC shall have a security code system that controls access to the unit as well as the actions to be taken (i.e., gathering data, calibration, etc.). All of the basic equations used in metering calculations shall be stored in the permanent memory, so that no changes to the equations can be made by the operator using any local device. The equations used in the computer shall be programmed in the EFC according to local mandatory standards. During factory acceptance tests, all equations shall be tested and verified.

7. The flow computer shall have a pulse output capable of activating a sampler. Proper barriers shall be installed between the sampler and the EFC to maintain the intrinsically safe environment.

8. The EFC shall be capable of transferring data to other computers through signal cable or microwave/radio communications, as specified in the job specifications. In addition, the self-contained solar powered units shall be capable of communicating with a hand-held device for data gathering, calibration and program changes.

9. The protocols for all systems shall be compatible.

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10. The self-contained solar powered units shall have an external liquid crystal display to display data. EFC shall be capable of being programmed to select the data being continually displayed. Flow rate units and units for other variables shall be specified in the job specifications.

3. Level

- API RP 551, Section 3 shall be the basis for the selection and installation of level devices. Refer to Tables A–3 and A–4 of Appendix A of this MEP for additional information.
- The references and requirements in MP 32-P-01 shall apply to this MEP.
- Devices containing mercury shall not be used in any level application.
- Tank gauges shall be of the type that permit remote transmission of liquid level.
- All tank level measurements shall include a pressure gauge, calibrated in meters (feet) of liquid level, as a backup to the primary level device.

4. Pressure

The references and requirements in MP 32-P-01 and API RP 551 apply to this MEP. For supplemental information and requirements refer to MP 32-P-19.

- A pressure instrument shall withstand the maximum pressure of the system to which it is connected. In addition, overrange protection, (at least 1.3 times the maximum scale reading), shall be furnished for all instruments. Gauge protectors shall be used with approval to protect against maximum pressure conditions.
- Ranges for pressure instruments shall be approximately twice the normal operating range. Suppressed-range instruments shall be used in control loops to ensure proper readability and control.
- Direct-reading scales and displays shall be used integrally or remotely with pressure instruments.
- Process connections for pressure instruments shall be NPS $^{3}/_{4}$ minimum (NPS = nominal pipe size, inches), including nipple or valve connections or both. Applications that call for connections of different sizes shall be approved.
- Maintainable pressure transmitters shall be used. Disposable transmitters shall be provided only with written approval.
- Intelligent (smart) transmitters shall be used for ease of maintenance and greater stability. Conventional transmitters shall be used if intelligent transmitters are economically unjustified.

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- Proper materials or diaphragm seals shall be used to protect instruments from corrosive service or plugging.

5. Temperature

The references and requirements of MP 32-P-01 and API RP 551, Section 5 shall apply to this Practice. Refer to Tables A–5 and A–6 for additional information.

Temperature measurement systems shall be compensated for ambient temperature variations and shall be protected for a maximum temperature over-range.

Temperature switches shall be "snap-acting" and either a bimetallic or filled system.

6. Modifications to API RP 551

Modifications to API RP 551 Section 3: Level

3.2.3. Modification: Readability

Level indicating instruments shall be located so that they can be read by the operator.

3.2.4. Modification: Connections to Vessels

1. Connections to boots and vessels shall be made horizontally, at an adequate distance above the bottom to avoid clogging by sediment. Connections to boots, flowlines or process nozzles are not allowed without written approval.
2. The minimum size of instrument connections allowed on vessels shall be as specified in MP 16-P-01, MP 32-P-19 and MP 12-P-01.
3. Liquid residence time (LRT) specified in project documents shall be the basis of liquid measurement range, which as a rule of thumb is between 20 percent and 80 percent of the volume. To determine the liquid measurement range, the following steps shall be taken:

    a) Determine minimum distance from vessel tangent line for placement of the bottom level connection. This shall be a function of the vessel fabrication and shall conform to MP 12-P-01. Factors of vessel rating, wall thickness and nozzle size and rating shall influence this dimension.

    b) Determine the least detectable measurement above the centerline of the nozzle. This will be influenced by connection orientation, standpipe or direct connected

instrument, piping configuration of the instrument connection and the manufacturer data for the selected instrument.

c) Determine 20 percent of the selected instrument range.

d) Add the results of Items 1, 2 and 3 above. This will give the least practical low liquid level for the LRT, referenced to the vessel tangent line.

3.2.5. Modification: Multiple Instrument Mounting

Level instrument piping shall conform to requirements in MP 01-P-02, MP 32-P-19 and MP 12-P-01.

3.2.9. Modification: Drains and Vents

Valves shall be installed at the highest points for both venting and steamout connections, as shown in Figure 10 of API RP 551, Section 3.

3.3.1. Modification: Locally Mounted Gauges

1. Visible lengths of level glasses shall extend a minimum of 25 mm (1 in) above and 25 mm (1 in) below the range of the level instrument or any independently mounted switch associated with the level measurement. A typical installation is shown in Figure 7 of API RP 551, Section 3. Where possible, level glasses shall be installed so they are visible from other level instruments measuring the same level.

2. Two or more gauge columns required to cover a level range shall be installed with at least a 25 mm (1 in) overlap.

   In multiple gauge installations, the gauges shall be independently isolated from the process piping or vessel. Standard gauge cocks (with built-in velocity checks) shall be furnished for all services, except where the viscosity of the liquid precludes the use of the gauge cocks. Gauge cocks shall be the offset type with union bonnet, NPS $^{3}/_{4}$ male unions at valve seat and gauge connections. The stem shall have handwheels and quick-closing threads, with a double-seated plunger to unseat the ball check before the cock is closed. The body shall be forged steel. Ball check, plunger seat and valve stem shall be Type 316 or 304 stainless steel. Where necessary, higher-grade material shall be used. Drain connections shall be a minimum NPS $^{1}/_{2}$ threaded and shall be provided with a drain valve. Vents and drains shall be considered branch piping and shall conform to the requirements of MP 16-P-01.

   Isolating block valves shall be provided for all gauge glass installations in addition to the gauge cock.

4. For interface service, gauges shall be mounted on the vessel with the top connections always submerged.

5. Level gauge glasses shall be top and bottom connected. The minimum ratings given in Table 1 shall be used for gauge glasses and gauge cocks.

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Table 1: Minimum Ratings for Gauge Glasses and Gauge Cocks

	Rating					
	40°C kPa gauge	**100°F psig**	**320°C kPa gauge**	**600°F psig**	**540°C kPa gauge**	**1000°F psig**
Reflex glasses	12,400	1800	9250	340		
Transparent glasses	6,900	1000	5100	740		
Tubular glasses	1,700	250				
Gage cocks	10,300	1500			3400	500

6. The illumination level requirement for gauge glass illuminators shall be as specified in MP 33-P-25. Illuminators shall be used on all transparent gauge glasses.

7. Gage glasses shall not be more than four sections. Typical lengths for level gauge glasses are as follows:

Number of Sections	**Total Visible Length of Glass**	
	mm	**in**
1	321	$12^{5}/_{8}$
2	679	$26^{3}/_{4}$
3	1038	$40^{7}/_{8}$
4	1397	55

Temperatures above 204°C (400°F) require special consideration.

8. If longer ranges are required, a combination of gauge glasses shall be used.

9. Visible lengths of gauge glasses shall be equal to or greater than the span of the level instrument.

10. In mediums corrosive to glass, the gauge glasses shall be protected against etching by the use of mica shields.

11. Non-frosting extensions shall be fitted to gauge glasses operating below 0°C (32°F).

3.4.2.1. Modification: Displacement Transmitter

1. Displacer instruments shall be furnished with rotatable head construction. Standard displacer lengths shall be used (14 in, 32 in, 48 in, 60 in).

2. Connections shall be NPS 2 minimum, ANSI Class 300 flanges, located top-side and bottom-bottom.

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3. External displacer type of liquid level instruments shall not be used in the following services:

   – Level range exceeds 1524 mm (60 in)

   – Services below -50°C

   – Liquefied gas and refrigerant services

3.4.3. Modification: Differential Pressure Transmitter

1. Differential pressure transmitters shall be used in services where the level range exceeds 1524 mm (60 in) and the service is below -50°C. These transmitters shall be used for both liquefied gas and refrigerant services.

2. Services such as viscous, slurry or waxy fluids shall require remote seal units with a flush or extended diaphragm seals. Installation of these devices shall require flange mounted dP cells.

3. Differential pressure transmitters installed in services where liquids boil at ambient temperatures shall be normally located above the vessel taps (refer to API RP 551, Section 3, Figure 14). As an exception, some applications may require that the transmitter be mounted below the vessel taps and the legs to the transmitter be sealed with a liquid heavier than the liquid in the vessel (refer to project specifications).

4. Special installations such as purged or flushed taps shall be considered when warranted by application. Such installations require approval.

5. Transmitters shall be provided with adjustable span, range suppression, range elevation and overrange protection.

6. Adjustment of the elevated-zero and suppressed-zero range shall be at least 100 percent of the maximum transmitter upper range value.

7. Transmitters used for head level measurement shall have a breather screen suitable for the project location on the atmospheric side of the transmitter.

3.4.6. Modification: Ultrasonic Level Transmitter

1. These level instruments can be used for contact or non-contact level measurements.

2. Ultrasonic level instruments shall not be used in foamy applications.

3. A stilling well/wave guide shall be installed for non-contacting measurement.

3.4.7. Modification: Capacitance and RF Level Transmitter

1. For interface applications where a displacer level device is not applicable, a vertically installed capacitance probe shall be used.

2. Capacitance probes shall have suitable coating for the particular application.

3. Capacitance level transmitters shall have a digital local indication in engineering units.

4. Capacitance probes for single point level indication shall be mounted horizontally.

3.5.2. Modification: Displacement Controllers

Where steam is used as a heating exchange medium with process hydrocarbon, steam traps shall not be used in the condensate lines. Steam condensate vessels with displacer-type instruments shall be installed (refer to Figure 1).

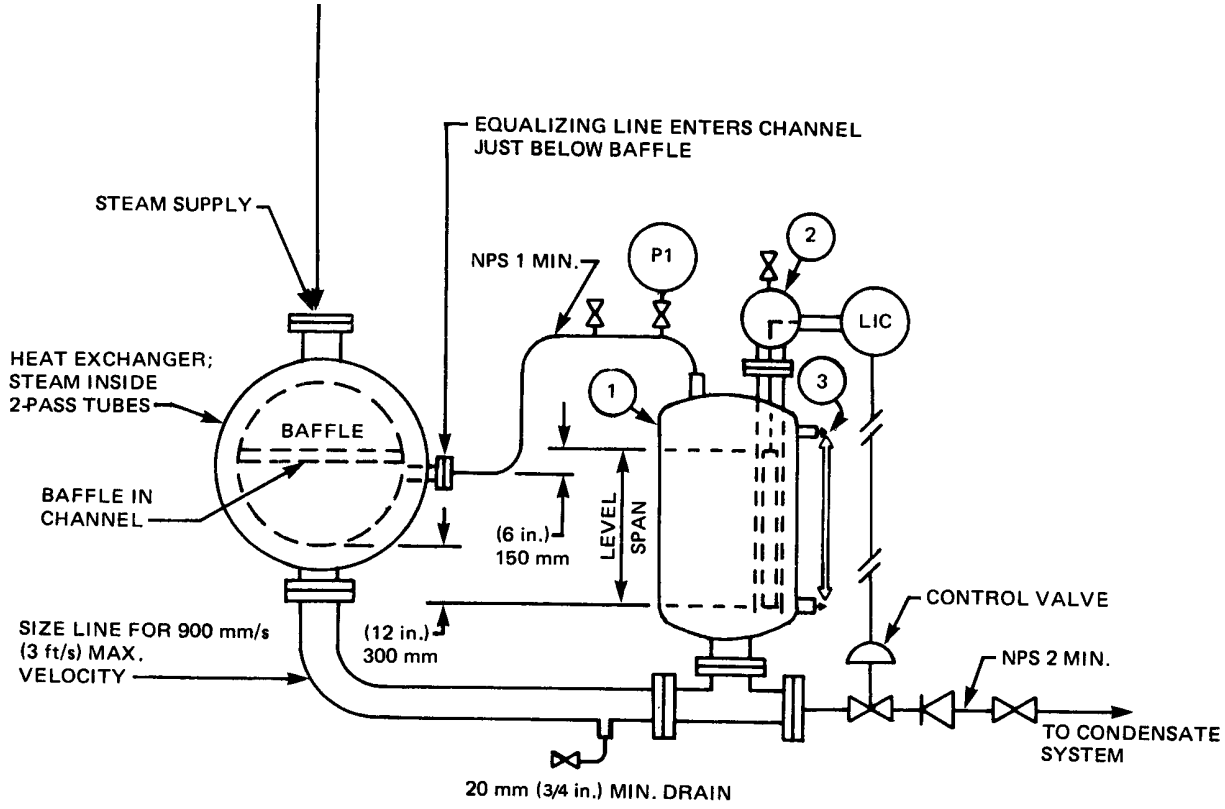

Figure 1: Steam Condensate Vessel with Displacer-Type Instrument

LEGEND:

1. Condensate pot 400 x 760 mm (16 x 30 in) with NPS 4 nozzle and slotted internal guide pipe for level displacer, if internal.
2. Pneumatic internal displacement type of level controller, flange mounted. External displacement type of level controller may be used as an alternative.
3. Level gage with velocity check gage valves.

3.5.3. Modification: Internal Ball-Float Controllers

1. Ball-float controllers, either for pilot operation or mechanical operation of control valves and signals, shall be used only for asphaltic, waxy, coking, particulate services

or for non-process applications. Control valves mechanically operated by a float shall have a double port and rotary stem and be no larger than NPS 3. Larger valves shall be pilot-operated, diaphragm motor control valves.

3.6. Modification: Level Switches

1. All critical alarm services, interlock systems and shutdown liquid level actuators shall be installed as shown in MP 00-P-02. Shutdown actuators shall be mounted on nozzles dedicated for their use only. Flanged-body level devices (refer to API RP 551, Section 3, Figure 18) shall be used in the aforementioned services to permit access to the float or displacer. Vents and drains shall be provided on the alarm switch side of the arrangement. Ball checks on the drain and gauge glass vents make draining of level switches difficult and therefore shall not be used to isolate the switch. Switches shall be installed so that their operation may be checked in situ.

   Electrode units shall be used for primary high- and low-level safety shutdown on steam boilers, as well as in other non-hydrocarbon services.

Modifications to API RP 551 Section 4: Pressure

4.2.5. Modification: Vibration

Gauges with extended tubing or subject to vibration shall be supported independently of piping or equipment.

4.2.6. Modification: Pulsation

Pressure gauges for severe pulsating services, such as reciprocating pumps and compressors, shall be helical primary actuated gauges with the closed end connected directly to the pointer shaft. In less severe pulsating services, liquid-filled case pressure gauges shall used.

For filled gauges, the filling plug shall act as a blowout seal at a maximum internal pressure of 70 kPa gauge (10 psig). Filled systems shall have a small air space above the liquid to prevent thermal expansion forces from acting on the Bourdon tube, which would oppose the measurement forces.

4.2.7. Modification: Purging and Sealing

Continuous-duty chemical seals shall be used to seal the instrument from overpressure. The chemical seals shall be compatible with the line specification and process. Gauges connected to the chemical seal systems shall have a "Do Not Disconnect" tag. The flexible capillary between seal and instrument shall be supported throughout its length. Any excess shall be coiled alongside the process point to facilitate withdrawal of the element.

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4.2.8.1. Modification: Piping

Bite-type compression fittings and seamless annealed stainless steel type 316 tubing shall be used. Inch series tubings and fittings shall be used (i.e., $^{1}/_{4}$, $^{3}/_{8}$ and $^{1}/_{2}$ inch OD etc.).

4.2.10. Modification: Element and Socket (Wetted) Materials

The minimum material of construction for pressure gauges shall be Type 316 stainless steel Bourdon tubes, sockets, stems and movements, unless otherwise specified. For saltwater service the minimum material shall be Monel.

4.3. Modification: Pressure Gauges and Switches

Pressure gauges shall be installed at the inlet and outlet of all heat transfer equipment in critical service. Where banks of exchangers are used in series, in parallel or in series-parallel, a pressure gauge shall be installed on the inlet and outlet of each series and/or parallel bank of exchangers. Valves and plugged connections for test gauges shall be installed between individual exchangers in the bank.

Pressure switches shall have an adjustable set point or a differential gap with a reference or calibrated scale. Where explosionproof, flameproof or weatherproof housings are used, an internal scale is acceptable; however, an external scale with protective covering is preferred for general-purpose housings. Dead-front or shrouded terminal blocks and entrance bushings to the case are required. For direct process connection or when the local environment is humid or corrosive, pressure switches with hermetically sealed switch mechanisms shall be used. Electrical entry and electrical connections shall be completely isolated from process connections and components in contact with the process.

When tamperproof switches are required, they shall have internally adjustable set points or locking devices on the external set point adjustment.

Safety pressure relief valves shall not be used as pressure regulators.

4.3.2. Modification: Supports

Gauges subject to vibration shall have support that is independent of the piping or equipment. Commercially available valves with a built-in support bracket and a bleeder valve may be used. Valve material shall comply with the line piping specification and rating. Where the pressure gauge is the only instrument on the process connection and close coupling is chosen, the block valve specified in MP 32-P-19 may be selected with the optional single NPS 2 in female union to allow for gauge orientation.

4.3.3. Modification: Safety Devices

The term "shall" is to be used in place of "should."

4.3.3. Modification: Siphons

Closed-coupled siphons rather than pigtails shall be used for hot condensable vapor service.

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4.3.5. Modification: Case Material & Size

Type 316 stainless steel pressure gauges shall be used.

Cases shall be a minimum of $4^1/_2$ in (115 mm) in diameter and shall be large enough to be readable at a distance of 10 ft.

Avoid use of plastic and aluminum cases since they are more susceptible to damage during construction and adversely affected by high process temperatures.

4.4.2b. Modification: Pressure Transmitters

Transmitters shall be supported by means other than the process connection and shall be installed to allow easy access from either grade or permanent platform. Transmitter output indicators shall be readable from grade or operating platform. When the transmitter is part of a control loop, its output shall be readable from its associated control valve manifold.

4.4.3. Modification: Differential Pressure Transmitters

Transmitters shall have a transmitted accuracy within ±0.1 percent to ±0.5 percent of the actual span for which it is calibrated. Smart electronic transmitters are preferred to analog electronic transmitters however approval is required when using smart transmitters in special applications such as compressor surge control and emergency shutdown.

Modifications to API RP 551 Section 5: Temperature

5.2.2. Modification: Thermowell Insertion Length

Insertion length shall be at least:

- Active element length + 50 mm (2 in) for liquids
- Active element length + 100 mm (4 in) for gases

5.2.3. Modification: Immersion Length

Unless otherwise approved, thermowells for services up to 90 m/s (300 ft/s) fluid velocities shall be fabricated as detailed in ASME PTC 19.3. Additional design requirements are:

1. Thermowell connections to equipment and piping shall be in accordance with the applicable MEPS and project specifications.
2. Thermowells shall be capable of withstanding stresses induced by stream velocity conditions. The wake frequency (commonly called the Strouhal frequency) shall not exceed 80 percent of the calculated natural frequency of the thermowell. Acceptable calculation methods are:

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- As specified in ASME PTC 19.3
- Contractor's equivalent method, subject to approval

5.2.4. Modification: Materials

Materials acceptable for standard thermowells shall be 304 stainless steel, as a minimum. Other materials shall be used as necessitated by process conditions or piping specifications.

5.2.5. Modification: Construction

1. Thermowell pressure and temperature ratings shall meet or exceed the allowable stress levels published in the latest edition of ASME standards.
2. Thermowells shall be used for all temperature instrumentation, unless otherwise specified.
3. Protective thermowells and test thermowells shall be bored to receive bimetallic, thermocouple or resistance elements.
4. With the exception of wells for filled system elements, the preferred element diameter for all temperature sensors shall be a nominal 6 mm ($^1/_4$ in).
   a) Thermowell bore shall be 6.45–6.66 mm (0.254–0.262 in).
   b) Alternate dimensions and configurations shall be considered where it can be shown that standard assemblies are not suitable or may affect operation of the equipment involved.
   c) All thermowells shall be drilled barstock.
5. Pipe wells, with spun and welded end, shall be provided for gas phase measurement in firebox and flue gas areas in heaters, boilers, furnaces, stacks and large vessels that operate at 482°C (900°F) and higher.
6. Measuring elements and thermowells shall be supplied as assemblies to ensure proper fit. Tip sensitive elements shall be provided with a mechanical means of ensuring a solid thermal connection with the thermowell tip (spring loaded, compression fitting, etc.).
7. Multipoint thermocouple assemblies are specific engineered products. Close coordination of the process requirements and vessel fabrication shall be considered during development.
8. Minimum requirements for multipoint assemblies include:
   a) Thermocouples require certification of calibration in the temperature region of operation to ensure specified accuracy and resolution.
   b) Lead wire, field termination and receiving equipment are to be tested and calibrated as a system by simulation of the certified curve from the thermocouple head or terminal enclosure.

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c) The configuration of the thermowell and thermocouple assembly shall satisfy the required time response as determined by the process needs. This may dictate whether the thermocouples are fixed or removable.

d) In hydrogen service, the thermowell and the thermocouple attachment shall be properly designed and sealed to contain the process fluid under maximum pressure and temperature due to hydrogen permeation or well failure.

e) If the thermocouples are designed to be removed on-line, a means to test and/or relieve pressure shall be provided before thermocouple removal.

5.3.2.2. Modification: Thermocouple Fabrication

Metal-sheathed, mineral-insulated, thermocouple assemblies with the measuring junction at the tip and electrically isolated from the metal sheath, as illustrated in detail B of API RP 551, Section 5, Figure 29, shall be used. The minimum diameter of the sheath shall be 6 mm ($^1/_4$ in).

5.3.2.3. Modification: Installation

Liquid-tight, PVC-jacketed, flexible steel conduit or armored flexible cable shall be used. These are as shown in Figure 31 of API RP 551, Section 5. Other types of construction may be used, subject to approval.

5.3.5. Modification: Extension Wires

1. Thermocouple extension wiring shall conform to the requirements of MP 32-P-21.

2. Thermocouples shall be of the two-wire type, with terminal blocks enclosed in a weatherproof head with a female threaded, gasketed cover.

3. Spare wires shall be terminated on terminal strips at each end. They shall be adequately identified as spares on the strips and on wiring diagrams and summaries.

4. Terminations for thermocouple extension wires, in field-mounted junction boxes or in control room termination cabinets, shall be of material identical to the thermocouple wires themselves. Two-terminal strips shall be equipped with thermocouple alloy terminal lugs (jumpers). Crimp-type or wire nut terminations shall not be permitted.

5. Refer to Table A–6 in Appendix A of this MEP for thermocouple wire color coding.

5.3.2.1. Modification: Thermocouple Applications General

1. Temperature controllers shall use dedicated primary elements. If two or more primary elements are required at the same location, they shall be installed in separate thermowells no more than 150 mm (6 in) apart.

2. Separate thermowell with thermocouple shall be furnished for checking all control applications.

3. Thermocouple instruments that are for control or alarm shall have upscale burnout protection, providing fail-safe control loop reaction, unless otherwise specified.

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4. Digital Readouts:

   a) The digital readout system shall accept, scale and linearize the appropriate thermocouple types and display a direct readout in engineering units.

   b) Point selections shall be on a random access basis, requiring no set sequence to read any given thermocouple.

5. Microprocessor based equipment shall be used for monitoring and control.

6. When a distributed control system (DCS) is not used for monitoring, the following shall apply:

   a) Multipoint temperature recorders shall be furnished with a minimum of 10 percent spare points.

   b) Conventional multipoint temperature indicators (nonmultiplexed) shall have switches as follows:

      - Locking type for indicator points.
      - Nonlocking type for checking recorder points where duplex thermocouples are not used.
      - A minimum of 10 percent spare switches shall be provided.

   c) Digital readout temperature indicators shall have a four-digit display (999.9) and signs (+ and -) as a minimum. The resolution shall be on the order of 0.1°F for Type J thermocouples or 0.5°F for Type K. A typical accuracy would be 0.5 percent of span.

   d) Thermocouple burnout (open circuit fault) protection/indication shall also be provided.

   e) The digital readout system shall accept, scale and linearize the appropriate thermocouple types and display a direct readout requiring no use of factor or ramp scale switches. Point selection shall be on a random access basis, requiring no set sequence to read any given thermocouple. Pushbutton selector switches may be used with digital indicators.

5.4.2. Modification: RTD

1. Elements shall be a three wire 6.4 mm outside diameter, sheathed (6.0 mm), 304 stainless steel jacket, Pt 100 ohm at 0°C. Calibration shall be according to DIN 43760.

2. RTD shall be specified as complete assemblies consisting of the thermocouple, well, head and head to well piping.

5.5. Modification: Dial Thermometers

1. Dial thermometers with 125 mm (5 in) diameter, adjustable-angle dials and weatherproof cases shall be used unless otherwise specified. These thermometers shall be installed in thermowells.

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2. If necessary for readability or in vibrating services, dial thermometer with sufficient capillary length shall be used. SAMA Class II vapor-filled capillary systems shall not be used.

3. Dial case shall be of 316 stainless steel construction

5.5.3. Modification: Tube Surface Temperature Measurement

Thermocouples measuring furnace tube wall temperatures shall be either of the two types using a minimum Type K thermocouples:

- Shielded Pad Type
  - These thermocouples, which are of Gay Engineering & Sales Co. patented design (Refracto-pad), shall be designed so that the thermocouple junction is fabricated as an integral part of the welding pad. The pad shall be 19.05 x 19.05 x 3.175 mm ($^3/_4$ x $^3/_4$ x $^3/_4$ in) thick Type 316 stainless steel as a minimum, pre-formed to the tube OD to which it will be welded. The sheath shall be filled with a magnesium oxide insulation and a Type 310 stainless steel shield filled with refractory shall be welded to the furnace tube for a minimum of 120 degrees of the tube circumference. The shield is to protect thermocouple junction/pad from direct furnace radiation.
- Knife-Edged Type
  - These thermocouples, which are of Exxon patented design, shall be used as an alternative with written approval. A complete design including attachment procedures shall be submitted for approval.

Welding procedures for all assembly types shall be subject to approval.

Welders performing work on these thermocouple assemblies shall be fully qualified per ASME SEC IX or equivalent.

A magnetic particle examination of each completed thermocouple and furnace tube assembly shall be required.

5.6.1. Modification: Filled Systems

Minimum length of sensing bulb and attached capillary tubing shall be 3 m (10 ft).

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Appendix: Tables

Table A–1: Orientation Table for Flow Sensors

	Type of Design			
	Elbow Taps	**Jet Deflection**	**Laminar Flowmeters**	**Magnetic Flowmeters**
Applicable to Detect the Flow Of:				
Clean Liquids	X		X	X[e]
Viscous Liquids	L		X	X[e]
Slurry	L			X[e]
Gas	X	X	X	
Solids				
Direct Mass Flow Sensor				
Volumetric Flow Detector	X	X	X	X
Flow Rate Sensor	X	X	X	X
Inherent Totalizer				
Direct Indicator				
Transmitter Available	X	X	X	X
Linear Output	SR	X	X	X
Rangeability	3:1[b]	25:1	10:1	10:1[i]
Pressure Loss Through Sensor	N	M	H	N
Approx. Straight Pipe-Run Requirement (Upstream Diam./Downstream Diam.)	25/10[g]	20/5[g]	15/5	5/3
Accuracy ***±% Full Scale** ****±% Rate** *****±% Registration**	5–10[*]	2[*]	$^1/_2$–5[*j]	$^1/_2$[**]–2[*]
Flow Range	10^1–$10^{4.75}$ gpm or m^3/hr $10^{2.1}$–$10^{4.5}$ SCFM or Sm^3/hr	$10^{-2.75}$–10^5 SCFM or Sm^3/hr	$10^{-3.9}$–$10^{1.5}$ gpm or m^3/hr $10^{-4.4}$–$10^{3.4}$ SCFM or Sm^3/hr	$10^{-1.7}$–10^5 gpm or m^3/hr

Orientation Table for Flow Sensors (Continued)

	Type of Design			
	Mass Flowmeters		Metering Pumps	Orifice (Plate or Integral Cell)
	Misc.	Coriolis		
Applicable to Detect the Flow Of:				
Clean Liquids	X	X	X	X
Viscous Liquids	X	X	X	L
Slurry	X	L	X	L
Gas	X	X		X
Solids	SD			
Direct Mass Flow Sensor	X	X		
Volumetric Flow Detector	X	X	X	X
Flow Rate Sensor	X	X		X
Inherent Totalizer	SD	SD	X	
Direct Indicator	SD	SD		
Transmitter Available	X	X	SD	X
Linear Output	X	X	X	SR
Rangeability	100:1	20:1	20:1	3:1[b]
Pressure Loss Through Sensor	A	H	–	H
Approx. Straight Pipe-Run Requirement (Upstream Diam./Downstream Diam.)	N	N	N	20/5[g]
Accuracy **[*]±% Full Scale** **[**]±% Rate** **[***]±% Registration**	$^1/_2$[**]	0.15–$^1/_2$[**]	$^1/_{10}$–1[*]	$^1/_2$[**]–2[*]
Flow Range	10–$10^{5.9}$ lbm/hr or kgm/hr 10^{-6}–$10^{3.75}$ SCFM or Sm^3/hr	10–$10^{5.9}$ lbm/hr or kgm/hr 10^{-6}–$10^{3.75}$ SCFM or Sm^3/hr	$10^{-6.1}$–10^3 gpm or m^3/hr	$10^{-2.35}$–$10^{6.4}$ gpm or m^3/hr $10^{-2.5}$–$10^{5.8}$ SCFM or Sm^3/hr

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Orientation Table for Flow Sensors (Continued)

	Type of Design			
	Pitot Tubes	Positive Displacement		Segmental Wedge
		Gas Meters	Liquid Meters	
Applicable to Detect the Flow Of:				
Clean Liquids	X		X	X
Viscous Liquids			X	X
Slurry	L			X
Gas	X	X		
Solids				
Direct Mass Flow Sensor				
Volumetric Flow Detector	X	X	X	X
Flow Rate Sensor	X			X
Inherent Totalizer		X	X	
Direct Indicator		X	X	
Transmitter Available	X	SD	SD	X
Linear Output	SR	X	X	SR
Rangeability	3:1[b]	10:1–200:1	10:1[i]	3:1
Pressure Loss Through Sensor	M	M	H	M
Approx. Straight Pipe-Run Requirement (Upstream Diam./Downstream Diam.)	30/5[g]	N	N	15/5
Accuracy ***±% Full Scale** ****±% Rate** *****±% Registration**	0.5-5*	$^1/_2$–1***	0.1–2**	3**
Flow Range	$10^{1.2}$–$10^{6.3}$ gpm or m^3/hr 10–$10^{5.8}$ SCFM or Sm^3/hr	$10^{-3.8}$–$10^{3.4}$ SCFM or Sm^3/hr	$10^{-3.3}$–$10^{4.7}$ gpm or m^3/hr	10–$10^{3.8}$ gpm or m^3/hr

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Orientation Table for Flow Sensors (Continued)

	Type of Design			
	Solids Flowmeters	**Target Meters**	**Thermal Meters (Mass Flow)**	**Turbine Flowmeters**
Applicable to Detect the Flow Of:				
Clean Liquids		X	X	X
Viscous Liquids	SD	X	L	L
Slurry	SD	L	L	
Gas		X	X	SD
Solids	X			
Direct Mass Flow Sensor	SD		X	
Volumetric Flow Detector	SD	X		X
Flow Rate Sensor	X	X	X	X
Inherent Totalizer	X			
Direct Indicator	SD	SD		
Transmitter Available	X	X	X	X
Linear Output	X	SR	L	X
Rangeability	20:1	4:1	20:1[i]	10:1[k]
Pressure Loss Through Sensor	–	H	A	H
Approx. Straight Pipe-Run Requirement (Upstream Diam./Downstream Diam.)	5/3	20/5	5/3	15/5[g]
Accuracy **[*]±% Full Scale** **[**]±% Rate** **[***]±% Registration**	$^1/_2$[**]–4[*]	0.5[*]–5[*]	1–2[*]	$^1/_4$[**]
Flow Range	$10^{2.1}$–10^5 lbm/hr or kgm/hr	10–$10^{3.5}$ gpm or m^3/hr $10^{.25}$–$10^{2.6}$ SCFM or Sm^3/hr	$10^{-3.1}$–$10^{3.1}$ gpm or m^3/hr 10^{-5}–$10^{4.4}$ SCFM or Sm^3/hr	$10^{-3.1}$–$10^{4.7}$ gpm or m^3/hr $10^{-3.8}$–10^6 SCFM or Sm^3/hr

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Orientation Table for Flow Sensors (Continued)

	Type of Design			
	V-Cone Flowmeter	Ultrasonic Flowmeters		Variable-Area Flowmeters
		Transit	Doppler	
Applicable to Detect the Flow Of:				
Clean Liquids	X	X		X
Viscous Liquids	L	L	L	L
Slurry	L		X	L
Gas	X		L	X
Solids			L	
Direct Mass Flow Sensor				
Volumetric Flow Detector	X	X	X	X
Flow Rate Sensor	X	X	X	X
Inherent Totalizer				
Direct Indicator				X
Transmitter Available	X	X	X	X
Linear Output	SR	X	X	X
Rangeability	3:1[b]	20:1	10:1	5:1
Pressure Loss Through Sensor	M	N	N	A
Approx. Straight Pipe-Run Requirement (Upstream Diam./Downstream Diam.)	2/5	15/5[g]	15/5[g]	N
Accuracy ***±% Full Scale** ****±% Rate** *****±% Registration**	$^1/_2$–2**	1**–2*	2–3*	$^1/_2$*–10**
Flow Range	10^{-1}–10^6 gpm or m^3/hr $10^{-1.75}$–$10^{5.3}$ ACFM or Sm^3/hr	10^{-1}–$10^{6.3}$ gpm[c] or m^3/hr $10^{-1.75}$–10^6 SCFM or Sm^3/hr	10^{-1}–$10^{6.3}$ gpm[c] or m^3/hr $10^{-1.75}$–10^6 SCFM or Sm^3/hr	10^{-4}–$10^{3.9}$ gpm or m^3/hr $10^{-5.25}$–$10^{4.1}$ SCFM or Sm^3/hr

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Orientation Table for Flow Sensors (Continued)

	Type of Design		
	Venturi Tubes	**Flow Nozzles**	**Vortex Shedding**
Applicable to Detect the Flow Of:			
Clean Liquids	X	X	X
Viscous Liquids	L		
Slurry	L	L	
Gas	X	X	X
Solids			
Direct Mass Flow Sensor			
Volumetric Flow Detector	X	X	X
Flow Rate Sensor	X	X	X
Inherent Totalizer			
Direct Indicator			
Transmitter Available	X	X	X
Linear Output	SR	SR	X
Rangeability	3:1[b]	3:1[b]	10:1[h]
Pressure Loss Through Sensor	M	H	H
Approx. Straight Pipe-Run Requirement (Upstream Diam./Downstream Diam.)	15/5[g]	20/5[g]	20/5
Accuracy **[*]±% Full Scale** **[**]±% Rate** **[***]±% Registration**	$^1/_2$[**]–1[*]	1[**]–2[*]	0.5–1.5[**]
Flow Range	$10^{-.8}$–$10^{6.3}$ gpm[c] or m^3/hr 10^0–$10^{5.25}$ SCFM or Sm^3/hr	$10^{-.8}$–$10^{6.3}$ gpm[c] or m^3/hr 10^0–$10^{5.25}$ SCFM or Sm^3/hr	$10^{-.1}$–$10^{4.2}$ gpm or m^3/hr $10^{-.5}$–$10^{4.2}$ ACFM or Sm^3/hr

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Orientation Table for Flow Sensors (Continued)

	Type of Design		
	Vortex Shedding Fluidic	**Vortex Shedding Oscillating**	**Weirs, Flumes**
Applicable to Detect the Flow of			
Clean Liquids	X	X	X
Viscous Liquids			L
Slurry			L
Gas			
Solids			
Direct Mass Flow Sensor			
Volumetric Flow Detector	X	X	X
Flow Rate Sensor	X	X	X
Inherent Totalizer			
Direct Indicator			
Transmitter Available	X	X	X
Linear Output	X	X	SD
Rangeability	20:1[h]	10:1[h]	100:1
Pressure Loss Through Sensor	H	H	M
Approx. Straight Pipe-Run Requirement (Upstream Diam./Downstream Diam.)	20/5	20/5	See Text
Accuracy ***±% Full Scale** ****±% Rate** *****±% Registration**	1–2**	0.5*	2-5*
Flow Range	10^{-1}–$10^{4.2}$ gpm or m^3/hr $10^{-.5}$–$10^{4.2}$ ACFM or Sm^3/hr	10^{-1}–$10^{4.2}$ gpm or m^3/hr $10^{-.5}$–$10^{4.2}$ ACFM or Sm^3/hr	$10^{-.5}$–$10^{6.2}$ gpm[c] or m^3/hr

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LEGEND FOR TABLE A–1 (Orientation Table For Flow Sensors):

L = Limited

SD = Some Designs

H = High

A = Average

M = Minimal

N = None

SR = Square Root

a = The data in this column is for general guidance only.

b = Inherent rangeability of primary device is substantially greater than shown. Value used reflects limitation of differential pressure sensing device, when 1% of actual flow accuracy is desired. With multiple-range intelligent transmitters, the rangeability can reach 10:1.

c = Pipe size establishes the upper limit.

d = Practically unlimited with the probe type design.

e = Must be conductive.

f = Can be re-ranged over 100:1.

g = Varies with upstream disturbance.

h = Can be more at high Re. No. services.

i = Up to 100:1 with high precision design.

j = Commercially available gas flow elements can be ±1% of rate.

k = More for gas turbine meters.

Table A–2: Flowmeter Selection Table

	Differential Pressure					**Magnetic**
	Orifice	**Venturi**	**Flow Nozzles and Tubes**	**Pitot Tubes**	**Elbow**	
Clean Liquids	1	1	1	1	1	1
Dirty Liquids	2	3	2	2	3	1
Corrosive Liquids	3	2	2	3	3	1
Viscous Liquids	3	2	2	2	2	3
Abrasive Slurries	4	2	2	4	3	1
Fibrous Slurries	4	2	2	4	2	1
Low Velocity Flows	1	2	2	2	4	3
Vapor or Gas	1	1	1	1	1	4
High Temperature Service	1	2	2	2	2	2

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	Differential Pressure					Magnetic
	Orifice	Venturi	Flow Nozzles and Tubes	Pitot Tubes	Elbow	
Cryogenic Service	1	2	2	2	2	4
Semi-Filled Pipes	4	4	4	4	4	2
Non-Newtonians	2	2	2	4	2	3
Open Channel	4	4	4	4	4	2

* Courtesy of Fischer & Porter.

LEGEND:

1. Designed for this service
2. Applicable for this service under certain conditions; consult manufacturer
3. Normally applicable for this service
4. Not applicable for this service

Flowmeter Selection Table (Continued)

	Mass		Oscillatory			Positive Displacement
	Coriolis	Thermal	Vortex Shedding	Fluidic	Vortex Precession	
Clean Liquids	1	2	1	1	1	1
Dirty Liquids	1	2	3	2	4	4
Corrosive Liquids	3	2	3	3	2	2
Viscous Liquids	1	2	2	2	2	1
Abrasive Slurries	1	2	4	4	4	4
Fibrous Slurries	3	2	4	4	4	4
Low Velocity Flows	3	3	4	4	4	1
Vapor or Gas	2	1	1	4	1	1
High Temperature Service	2	2	2	2	2	2
Cryogenic Service	2	4	2	2	4	2

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	Mass		Oscillatory			Positive Displacement
	Coriolis	Thermal	Vortex Shedding	Fluidic	Vortex Precession	
Semi-Filled Pipes	4	4	4	4	4	4
Non-Newtonians	1	2	4	4	4	4
Open Channel	4	4	4	4	4	4

Flowmeter Selection Table (Continued)

	Target	Turbine	Ultrasonic		Variable Area	Weirs and Flumes
			Transit Time	Doppler		
Clean Liquids	1	1	1	4	1	1
Dirty Liquids	3	2	2	1	3	3
Corrosive Liquids	3	2	2	2	3	2
Viscous Liquids	3	3	2	2	3	4
Abrasive Slurries	2	4	4	2	4	2
Fibrous Slurries	4	4	4	2	4	2
Low Velocity Flows	2	2	2	2	2	3
Vapor or Gas	1	1	2	4	1	4
High Temperature Service	2	2	4	4	3	4
Cryogenic Service	2	2	2	4	4	4
Semi-Filled Pipes	4	4	4	4	4	1
Non-Newtonians	2	4	4	2	4	4
Open Channel	4	3	3	4	4	1

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Flowmeter Selection Table (Continued)

	Flowmeter: Orifice						
	Square-Edged	**Honed Meter Run**	**Integral**	**Quadrant/Conic Edge**	**Eccentric**	**Segmental**	**Annular**
Square root scale: Maximum single range 4:1							
Pipe Size, in (mm)	>1.5 (40)	0.5–1.5 (12–40)	<0.5 (12)	>1.5 (40)	>2 (50)	>4 (100)	>4 (100)
Gas (Vapors)							
Clean	1	1	1	4	3	3	3
Dirty	4	4	4	4	1	1	1
Liquids							
Clean	1	1	1	1	3	3	3
Viscous	4	3	1	1	4	4	4
Dirty	3	4	4	3	1	1	1
Corrosive	3	3	3	3	3	3	3
Slurries:							
Fibrous	4	4	4	4	4	4	4
Abrasive	4	4	4	4	4	4	4
Temperature °F (°C)	Process temperature to 1000°F (540°C); transmitter limited to -30–250°F(-30–120°C)						
Pressure, psig (kPa)	To 4000 psig (41,000 kPa)						
Accuracy, Uncalibrated (Including Transmitter)	± 1–2% URV	± 1% URV	± 2–5% URV	± 2% URV	± 2% URV	± 2% URV	± 2% URV
Reynolds Number or Viscosity**	R_D > 2000	R_D > 1000	R_D > 100	R_D > 200	R_D > 10,000	R_D > 10,000**	R_D > 10,000**

** According to other sources, this minimum Reynolds Number should be much higher.

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Flowmeter Selection Table (Continued)

	Flowmeter						
	Target	**Venturi**	**Flow Nozzle**	**Low Loss**	**Pitot**	**Annubar**	**Elbow**
Pipe Size, in (mm)	0.5–4 (12–100)	>2 (50)	>2 (50)	>3 (75)	>3 (75)	>1 (25)	>2 (50)
Gas (Vapors)							
Clean	1	1	1	1	1	1	1
Dirty	1	3	3	4	4	4	3
Liquids							
Clean	1	1	1	1	1	1	1
Viscous	1	3	3	4	3	4	4
Dirty	1	3	3	4	4	4	3
Corrosive	3	3	3	1	3	3	3
Slurries:							
Fibrous	4	3	4	4	4	4	3
Abrasive	4	3	4	4	4	4	3
Temperature °F (°C)	Process temperature to 1000°F (540°C); transmitter limited to –30–250°F (-30–120°C)						
Pressure, psig (kPa)	To 4000 psig (41,000 kPa)						
Accuracy, Uncalibrated (Including Transmitter)	± 1.5–5% URV	± 1– ± 2% URV	± 1– ± 2% URV	± 1.25% URV	± 5% URV	± 1.25% URV	± 4.25% URV
Reynolds Number or Viscosity**	R_D > 100	R_D > 75,000	R_D >10,000	R_D > 12,800	No limit	R_D > 10,000**	R_D > 10,000**

* Courtesy of RW Miller's Flow Measurement Handbook

****** According to other sources, this minimum Reynolds Number should be much higher.

LEGEND FOR TABLE A–2 (Flowmeter Selection Table):

1. Designed for this service
2. Applicable for this service under certain conditions; consult manufacturer
3. Normally applicable for this service

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4. Not applicable for this service

Table A–3: Orientation Table for Level Detectors

Type			Air Bubblers	Capacitance	Conductivity Switch	Diaphragm
Level Range:						
	In feet		0–200	0–200	Point Sensor	0–45
	In meters		0–67	0–67		0–14
Max Temp (°F) **°C = (°F-32)/1.8**			UL	2,000	1800	350
Available as Noncontact				X		
Inaccuracy **(1 in = 25.4 mm)**			1-2% FS	1–2%FS	$^{3}/_{4}$ in	0.5% FS
Cost:						
	Under $1000		X	X	X	X
	$1000–$5000			X		X
	Over $5000					
Available Designs:						
	Switch		X	X	X	X
	Local Indicator		X			
	Transmitter		X	X		X
Applications:						
	Liquids	**Clean**	G	G	F	G
		Viscous	F	F–G	P	F
		Slurry/ Sludge	P	F	F	F
		Interface	F	G–L	L	
		Foam		P	L	
	Solids	**Powder**		F	L	F
		Chunky		F	L	F

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Type		Air Bubblers	Capacitance	Conductivity Switch	Diaphragm
	Sticky		P	L	P
Limitations		Introduces foreign substance into process; high maintenance	Interface between conductive layers and detection of foam is a problem.	Can detect interface only between conductive and nonconductive liquids. Field effect design for solids.	Switches only for solids service.

Orientation Table for Level Detectors (Continued)

Type			Differential Pressure	Displacer	Float	Laser
Level Range:						
	In feet		0–72	0–48	0–13	7–56
	In meters		0–22	0–16	0–4	2–17
Max Temp (°F) **°C = (°F-32)/1.8**			1200	850	500	UL
Available as Noncontact						X
Inaccuracy **(1 in = 25.4 mm)**			0.1% AS	0.5% FS	1% FS	0.5 in
Cost:						
	Under $1000		X	X	X	
	$1000–$5000		X	X		
	Over $5000					X
Available Designs:						
	Switch		X	X	X	
	Local Indicator		X	X	X	
	Transmitter		X	X	X	X
Applications:						
	Liquids	**Clean**	E	E	G	L
		Viscous	G–E	P	P	G

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Type		Differential Pressure	Displacer	Float	Laser
	Slurry/ Sludge	G	P	P	G
	Interface	P	F–G	F	
	Foam				F
Solids	**Powder**				F
	Chunky				F
	Sticky				F
Limitations		Only extended diaphragm seals or repeaters can eliminate plugging. Purging and sealing legs are also used.	Not recommended for sludge or slurry service.	Moving parts limit most designs to clean service. Only preset density floats can follow interfaces.	Limited to cloudy liquids or bright solids in tanks with transparent vapor spaces.

Orientation Table for Level Detectors (Continued)

Type		Level Gauges	Microwave Switch	Optical Switch	Radar
Level Range:					
	In feet	0–7	Point Sensor	Point Sensor	0–200
	In meters	0–2			0–67
Max Temp (°F) **°C = (°F-32)/1.8**		700	400	260	450
Available as Noncontact			X	X	X
Inaccuracy **(1 in = 25.4 mm)**		0.25 in	0.5 in	0.25 in	0.12 in
Cost:					
	Under $1000	X	X	X	
	$1000–$5000		X	X	
	Over $5000				X
Available Designs:					

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Type			Level Gauges	Microwave Switch	Optical Switch	Radar
	Switch			X	X	
	Local Indicator		X			X
	Transmitter					X
Applications:						
	Liquids	**Clean**	G	G	G	G
		Viscous	F	G	F	G
		Slurry/ Sludge	P	F	E	F
		Interface	F	G	F–G	P
		Foam			F	
	Solids	**Powder**		G	F	P
		Chunky		G	P	F
		Sticky		F	F	P
Limitations			Glass is not allowed in some processes.	Thick coating is a limitation.	Refraction-type for clean liquids only; reflection-type requires clean vapor space.	Interference from coating, agitator blades, spray or excessive turbulence.

Orientation Table for Level Detectors (Continued)

Type		Radiation	Resistance Tape	Rotating Paddle Switch	Slip Tubes
Level Range:					
	In feet	0–150	0–100	Point Sensor	0–15
	In meters	0–50	0–34		0–5
Max Temp (°F) **°C = (°F-32)/1.8**		UL	225	500	200
Available as Noncontact		X			
Inaccuracy **(1 in = 25.4 mm)**		0.25 in	0.5 in	1 in	0.5 in

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Type			Radiation	Resistance Tape	Rotating Paddle Switch	Slip Tubes
Cost:						
	Under $1000				X	X
	$1000–$5000		X	X		
	Over $5000		X			
Available Designs:						
	Switch		X			
	Local Indicator			X		
	Transmitter		X	X		
Applications:						
	Liquids	**Clean**	G	G		F
		Viscous	E	G		P
		Slurry/ Sludge	E	G		P
		Interface	G			
		Foam	F			
	Solids	**Powder**	G		G	
		Chunky	E		F	
		Sticky	E		P	
Limitations			Requires NRC license.	Limited to liquids under near-atmospheric pressure and temperature conditions.	Limited to detection of dry, noncorrosive, low-pressure solids.	An unsafe manual device.

Orientation Table for Level Detectors (Continued)

Type		Tape Type/Level Sensors	Thermal	TDR/PDS	Ultrasonic	Vibrating Switches
Level Range:						
	In feet	0–200	0–24	0–160	0–200	Point Sensor

Type			Tape Type/Level Sensors	Thermal	TDR/PDS	Ultrasonic	Vibrating Switches
	In meters		0–67	0–8	0–50	0–67	
Max Temp (°F) °C = (°F-32)/1.8			300	850	221	300	300
Available as Noncontact						X	
Inaccuracy (1 in = 25.4 mm)			0.1 in	0.5 in	3 in	1% FS	0.2 in
Cost:							
	Under $1000			X		X	X
	$1000–$5000		X	X	X	X	
	Over $5000						
Available Designs:							
	Switch			X		X	X
	Local Indicator		X				
	Transmitter		X	X	X	X	
Applications:							
	Liquids	Clean	E	G	F	F–G	F
		Viscous	F	F	F	G	G
		Slurry/ Sludge	P	F	F	G	G
		Interface	G	P		F–G	F
		Foam		F		F	
	Solids	Powder	G		G	F	F
		Chunky	F		G	F	G
		Sticky	F		F	G	G
Limitations			Only the inductively coupled float is suited for interface measurement. Float hangup is a potential problem with most designs.	Foam and interface detection is limited by the thermal conductivi-ties involved.	Limited performanc e on sticky process materials.	Presence of dust, foam, dew in vapor space; sloping or fluffy process material interferes with performance.	Excessive material buildup can prevent operation.

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Courtesy of the Instrument Engineers' Handbook: Process Measurement & Analysis, 3rd edition, by Bela G. Liptak, Chilton Book Company, Radnor, PA © 1995

LEGEND FOR TABLE A–3 (Orientation Table for Level Detectors):

TDR	Time Domain Reflectometry	**FS**	In percent of full scale
PDS	Phase Difference Sensors	**G**	Good
AS	In percent of actual span	**L**	Limited
E	Excellent	**P**	Poor
F	Fair	**UL**	Unlimited

Table A–4: Level Sensor Selection Guide

	Beam Breaker	**Bubbler**	**Capacitance**	**Conductive**	**Differential Pressure**
Liquids					
Point	—	1	1	1	2
Continuous	—	1	1	—	1
Liquid/Liquid Interface					
Point	—	—	1	2	2
Continuous	—	—	1	—	2
Foam					
Point	2	—	1	1	—
Continuous	—	—	2	—	—
Slurry					
Point	—	3	1	1	2
Continuous	—	2	2	—	2
Suspended Solids					
Point					
Continuous	—	—	—	—	—
	—	—	—	—	—

	Beam Breaker	Bubbler	Capacitance	Conductive	Differential Pressure
Powdery Solids					
Point	1	—	2	3	3
Continuous	—	—	2	—	3
Granular Solids					
Point	1	—	1	3	—
Continuous	—	—	2	—	—
Chunky Solids					
Point	3	—	2	3	—
Continuous	—	—	2	—	—
Sticky Moist Solids					
Point	1	—	1	1	—
Continuous	—	—	2	—	—

Level Sensor Selection Guide (Continued)

	Electromechanical						Gauges	
	Diaphragm	Displacer	Float	Float/ Tape	Paddle Wheel	Weight/ Cable	Glass	Magnetic
Liquids								
Point	1	1	1	3	—	3	1	1
Continuous	1	2	—	1	—	1	1	1
Liquid/Liquid Interface								
Point	2	2	2	—	—	—	2	—
Continuous	—	2	—	—	—	—	2	—
Foam								
Point	—	—	—	—	—	—	3	3
Continuous	—	—	—	—	—	—	3	3

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	Electromechanical						Gauges	
	Diaphragm	**Displacer**	**Float**	**Float/ Tape**	**Paddle Wheel**	**Weight/ Cable**	**Glass**	**Magnetic**
Slurry								
Point	2	3	3	—	3	—	3	3
Continuous	2	2	—	3	—	1	3	3
Suspended Solids								
Point								
Continuous	—	—	—	—	—	—	—	—
	—	—	—	—	—	1	—	—
Powdery Solids								
Point	1	—	—	—	2	—	—	—
Continuous	3	—	—	—	—	1	—	—
Granular Solids								
Point	1	—	—	—	1	—	—	—
Continuous	—	—	—	—	—	1	—	—
Chunky Solids								
Point	3	—	—	3	—	—	—	2
Continuous	—	—	—	—	1	—	—	2
Sticky Moist Solids								
	2	—	—	2	—	—	—	3
Point	3	—	—	—	1	—	—	3
Continuous								

Level Sensor Selection Guide (Continued)

	Inductive	**Micro-wave**	**Radiation**	**Sonic Echo**			**Thermal**	**Vibration**
				Sonar	**Sonic**	**Ultra-sonic**		
Liquids								
Point	—	1	1	—	1	1	1	2
Continuous	—	1	1	—	1	2	—	—

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	Inductive	Micro-wave	Radiation	Sonic Echo			Thermal	Vibration
				Sonar	Sonic	Ultra-sonic		
Liquid/Liquid Interface								
Point	—	—	—	2	3	2	1	3
Continuous	—	—	—	2	3	2	—	—
Foam								
Point	—	—	—	—	—	—	2	—
Continuous	—	—	—	—	—	—	—	—
Slurry								
Point	2	1	1	—	1	1	2	2
Continuous	—	1	1	3	1	2	—	—
Suspended Solids								
Point	—	—	1	1	2	1	—	1
Continuous	—	—	1	1	2	1	—	—
Powdery Solids								
Point	2	1	1	—	—	—	—	1
Continuous	2	2	1	—	3	3	—	—
Granular Solids								
Point	2	1	1	—	1	2	—	1
Continuous	2	1	1	—	1	2	—	—
Chunky Solids								
Point	2	1	1	—	1	1	—	2
Continuous	2	1	1	—	1	2	—	—
Sticky Moist Solids								
Point	3	1	1	—	2	2	—	1
Continuous	3	1	1	—	1	2	—	—

Courtesy of I&CS/Endress & Hauser, Inc.

LEGEND TO TABLE A–4 (Level Sensor Selection Guide):

1 = Good

2 = Fair

3 = Poor

– = Not applicable

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Table A–5: Thermocouple Comparison Table

ISA Type Designation		**B**	**E**	**J**	**K**	**R**	**S**
Positive Wire	**Numbers = Per-centages**	Pt70-Rh30	Chromel	Iron	Chromel	Pt87-Rh13	Pt90-Rh10
Negative Wire		Pt94-Rh6	Constantan	Constantan	Alumel	Platinum	Platinum
Millivolts per °F		.0003-.006	.015-.042	.014-.035	.009-.024	.003-.008	.003-.007
Recomm. Range Limits Temp °F*	**Min.**	32	-300	32	-300	32	32
	Max.	3380	1800	1500	2300	3000	3200
Scale Linearity		Same as for type R couple	Good	Good; nearly linear from 300-800	Good; most linear of all TCs	Good at high temps. Poor below 1000°F	Same as R
Atmosphere Environment Recommended		Inert or slow oxidizing	Oxidizing	Reducing	Oxidizing	Oxidizing	Oxidizing
Favorable Points		—	Highest emf/°F	Most economical	Most linear	Small size, fast response	Same as R
Less Favorable Points		—	Larger drift than other base metal couples	Becomes brittle below 32°F	More expensive than T or J	More expensive than type K	More expensive than type K

$$*^{\circ}\mathbf{C} = \frac{^{\circ}\mathbf{F} - \mathbf{32}}{\mathbf{1.8}}$$

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Thermocouple Comparison Table (Continued)

ISA Type Designation		**T**	**Y**	**—**	**—**	**—**	**—**
Positive Wire	**Numbers = Per-centages**	Copper	Iron	Tungsten	W94-Re6	Copper	Ir40-Rh60
Negative Wire		Constantan	Constantan	W74-Re26	W74-Re26	Gold-Cobalt	Iridium
Millivolts per °F		.008-.035	.022-.033	.001-.012	.001-.010	.0005-.025	.001-.004
Recomm. Range Limits Temp °F*	**Min.**	-300	-200	0	0	-450	0
	Max.	750	1800	4200	4200	0	3800
Scale Linearity		Good but crowded at low end	About same as type J	Same as R	Same as R	Reasonable above 60°K	Same as R
Atmosphere Environment Recommended		Oxidizing or reducing	Reducing	Inert or vacuum	Inert or vacuum	—	Inert
Favorable Points		Good resist. to corrosion from moisture	—	High temperature	Same as previous	Good output at very low temperature	—
Less Favorable Points		Limited temperature	Not industrial standard	Brittle, hard to handle, expensive	Slightly less brittle than previous	Expensive lab.- type TC	Brittle, expensive

$$*^{\circ}\mathbf{C} = \frac{^{\circ}\mathbf{F} - \mathbf{32}}{\mathbf{1.8}}$$

Courtesy of the Instrument Engineers' Handbook: Process Measurement & Analysis, 3rd edition, by Bela G. Liptak, Chilton Book Company, Radnor, PA © 1995

Table A–6: Differences in Color Codes Between the U.S. and IEC

Thermocouple type	+/-	Primary conductor		Overall jacket	
		U.S.	IEC	U.S.	IEC
T	+	Blue	Brown	Blue	Brown
	-	Red	White		
J	+	White	Black	Black	
	-	Red	White		
E	+	Violet		Violet	
	-	Red	White		
K	+	Yellow	Green	Yellow	Green
	-	Red	White		
N	+	Orange	Pink	Orange	Pink
	-	Red	White		
R/S	+	Black	Orange	Green	Orange
	-	Red	White		

Courtesy of the Instrument Engineers' Handbook: Process Measurement & Analysis, 3rd edition, by Bela G. Liptak, Chilton Book Company, Radnor, PA © 1995

NOTE TO TABLE A–6 (Differences in Color Codes Between the U.S. and IEC): Overall jackets for intrinsically safe circuits are blue.

Wiring for Instrumentation and Digital Systems

MP 32-P-21

August 1998 Draft

Scope

This Mobil Engineering Practice (MEP) covers the minimum requirements for electrical and optical signals for interconnection of industrial instruments and computer components.

Version 0

Table of Contents

Scope **1**

1. References **4**

1.1. MEPS–Mobil Engineering Practices 4

1.2. Mobil Data Sheets 4

1.3. API–American Petroleum Institute 4

1.4. IEC–International Electrotechnical Commission 5

1.5. ISA–Instrument Society of America 5

1.6. NFPA–National Fire Protection Association 5

1.7. UL–Underwriters Laboratories 5

2. General **5**

3. Electrical Safety Systems **6**

3.1. General 6

3.2. Explosion-Proof 6

3.3. Nonincendive 6

3.4. Safe 7

3.5. Increased Safety 7

3.6. Purged Enclosures 7

3.7. Selection of Equipment for Hazardous Atmospheres Using International Standards 8

4. Wire and Cable **8**

4.1. Materials 9

4.2. Cable Requirements 9

4.3. Conductor Sizes 9

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4.4. DC Power Supply 9
4.5. Data Communication Cables 9
4.6. Fiber Optic Cable 10
4.7. PVC Installation 10
4.8. Field Wiring 11
4.9. Homerun Cables 13
4.10. Cross Connections and Interconnections 14
4.11. Digital Communication Cables 15
5. Entries / Terminations 17
5.1. Control Room Entries 17
5.2. Field Instrument Connections 17
5.3. Field Junction Boxes 18
5.4. Remote Instrument Enclosure Entries and Terminations 21
6. Mechanical and Fire Protection of Wire and Cable 22
6.1. Mechanical Protection 22
6.2. Fire Protection 22
6.3. Prevention of Gas and Vapor Passage in Cables and Raceways 24
7. Belowgrade Installations 25
7.1. Types of Belowgrade Installations 25
8. Abovegrade Installations 29
8.1. Process Units 29
8.2. Buildings 29
Modifications to API RP 552 29

1. References

The following publications form a part of this Practice. Unless otherwise specified herein, use the latest edition.

1.1. MEPS–Mobil Engineering Practices

MP 32-P-01	General Requirements for Instrumentation
MP 32-P-05	Panels, Enclosures and Video Display Consoles
MP 33-P-23	Electrical - Raceway & Cable Tray Installations
MP 33-P-24	Electrical - Direct Burial Armored Cable Systems
MP 70-P-01	Loss Prevention - Facilities
MP 70-P-05	Fireproofing

1.2. Mobil Data Sheets

Mobil Data Sheets	Mobil Data Sheet Home Page
T3221C01	Wiring for Instrumentation & Digital Systems - Instrument Cable - Customary Units
T3221M01	Wiring for Instrumentation & Digital Systems - Instrument Cable - Metric Units
T3221C02	Wiring for Instrumentation & Digital Systems - Description of Cable Assemblies - Customary Units
T3221M02	Wiring for Instrumentation & Digital Systems - Description of Cable Assemblies - Metric Units

1.3. API–American Petroleum Institute

API RP 14F	Recommended Practice for Design and Installation of Electrical Systems for Offshore Production Platforms Third Edition
API RP 552	Transmission Systems First Edition

1.4. IEC–International Electrotechnical Commission

IEC 60079	Electrical Apparatus for Explosive Atmospheres (1983)

1.5. ISA–Instrument Society of America

ISA MC96.1	Temperature Measurement Thermocouples
ISA RP12.6	Wiring Practices for Hazardous (Classified) Locations Instrumentation Part 1: Intrinsic Safety
ISA S12.12	Nonincendive Electrical Equipment for Use in Class I and II, Division 2 and Class III, Divisions 1 and 2 Hazardous (Classified) Locations

1.6. NFPA–National Fire Protection Association

NFPA 70	National Electrical Code 1996 Edition Errata #1; Tentative Interim Amendment 1996
NFPA 496	Standard for Purged and Pressurized Enclosures for Electrical Equipment (National Fire Codes, vol. 7)

1.7. UL–Underwriters Laboratories

UL 913	UL Standard for Safety Intrinsically Safe Apparatus and Associated Apparatus for Use in Class I, II, and III, Division I, Hazardous (Classified) Locations Fifth Edition
UL 1424	UL Standard for Safety Cables for Power-Limited Fire-Alarm Circuits Second Edition

2. General

The minimum requirements for design of electrical and optical signals for interconnection of industrial instruments and computer components shall be in accordance with requirements of this MEP, unless superceded by more stringent local regulations.

3. Electrical Safety Systems

3.1. General

The recommended equipment selection, circuit design and installation method for reducing the risk of explosions and fires in classified areas are as follows:

1. Specify field instruments that carry, as a minimum, explosion-proof and intrinsically safe certification. Nonincendive certification shall be sought for transmitters, I/P convertors and other general-use instruments. Instruments with intrinsically safe certification typically meet all requirements for nonincendive circuits.
2. Design all 4–20 mA and digital circuits in Class I, Division 2 areas to be nonincendive. This requirement is easily met for field instruments applicable to refineries, gas plants and petrochemical plants.
3. Use intrinsically safe barriers for all circuits going to Class I, Division 1 areas.
4. Use certified explosion-proof housings and seals for devices in custom circuits.
5. Use purging methods only when other options are exhausted.

3.2. Explosion-Proof

Explosion-proof instruments and installations shall meet the requirements of NFPA 70, Section 500.

All single-function electronic (transmitters, I/P convertors, etc.) and electrical (switches, solenoids, etc.) devices in classified areas shall be contained in metallic housings. Explosion-proof housings typically supplied as an integral part of most field instruments provide the necessary mechanical and environmental protection required.

Devices in custom circuits in classified locations shall be enclosed in certified explosion-proof housings. Typically, these circuits include switches, relays and indicators for local operator interface. Explosion-proof housings shall be chosen over purged enclosures where both are feasible.

3.3. Nonincendive

Nonincendive circuit design shall be used for all Division 2 areas. The design of nonincendive circuits shall be in accordance with the requirements of ISA S12.12. All devices in a circuit, including wiring, shall conform to the criteria of ISA S12.12. In particular, the wire and the field devices shall meet the inductive and capacitive values given in ISA S12.12. This will require calculations showing that the complete loop, including cable inductance and capacitance as well as device inductance and capacitance,

meets the ISA S12.12 requirements. As a minimum, the following requirements shall apply:

1. All 4-20 mA input and output loops shall have an energy limiting device (to meet the nonincendive requirements), either within the control equipment by supplier design or in the field terminal strip within the unclassified area.
2. All thermocouple, RTD, etc., loops shall be designed to be nonincendive.
3. Junction boxes containing terminations of wires that are current-limited for nonincendive circuits shall not contain wires that are not current-limited.
4. In general, current-limited (nonincendive circuits) wires and terminations in unclassified (non-hazardous) areas shall be kept separate from circuits which are not current-limited.

Nonincendive electrical safety systems shall be identified to clearly inform all personnel using and working in the facility that the circuits are of nonincendive design.

- Terminal areas, cabinets, and field junction boxes shall be labeled with one-inch high letters stating "NONINCENDIVE ELECTRICAL WIRING SYSTEM."
- Electrical drawings, such as loop drawings and other schematics, shall include a general note stating "NONINCENDIVE ELECTRICAL WIRING SYSTEM."

3.4. Safe

Wherever electrically feasible, intrinsically safe systems shall be used for Division 1 locations. Intrinsically safe systems shall be designed to meet the requirements of ISA RP12.6 and shall require certification for all components and circuits.

Separation of wires and termination of intrinsically safe circuits from nonintrinsically safe circuits is required. Additional requirements are detailed in NFPA 70, Article 504.

Intrinsically safe circuits shall be marked by labels on field devices, on junction boxes and in terminal areas. Cable jackets shall be marked by color coding (light blue).

3.5. Increased Safety

In general, increased safety design is not required. Increased safety design is necessary only where local practices and codes require. Increased safety design shall not pre-empt the venting and sealing practices described in this Practice.

3.6. Purged Enclosures

Where complexity, size and other requirements preclude the use of the above methods for electrical safety in classified locations, enclosures shall be purged in accordance with the requirements of NFPA 496.

3.7. Selection of Equipment for Hazardous Atmospheres Using International Standards

- Equipment in this context refers to all instrumentation and installation system components, including glands and junction boxes.
- The applicable standards shall be IEC 60079, Parts 0–19. The nearest equivalent in the country of use may be used with Mobil approval.
- The selection of the type of protection to be used shall be based on the selection guidelines in IEC 60079, Part 14.
- Certificates are required for all equipment.
  - The certifying authority may be any recognized European Community authority (CENELEC).
  - An alternate authority may be used with Mobil approval. Manufacturer certification may be allowed for Ex "e" equipment in Zone 2 areas with Mobil approval (refer to IEC 60079, Part 14). Such approval shall be on the basis of a specific manufacturer and type of equipment.
- The preferred technique for all Zone 2 (Division 2) equipment is Ex "e" or Ex "n." Refer to IEC 60079, Part 7 and Part 15.
- Barrier glands shall be used on armored cable connected to all explosion-proof or flameproof (IEC 60079, Part 1, Ex "d") equipment. Note that this is in addition to any requirement for barrier glands to prevent the passage of gas and vapor through the cable.

4. Wire and Cable

Three common wiring methods, as follows, are acceptable and shall be selected based on the individual requirements of the job:

1. Type Metal Clad (MC) cable in a gas/vapor-tight continuous aluminum sheath, with an overall PVC (or other suitable material) jacket, in trays or attached to adequate mechanical supports
2. Rigid copper-free aluminum, galvanized steel or PVC-coated galvanized steel conduit with instrument wire and cable
3. Power Limited Tray Cable and Thermocouple (PLTC/TC) non-armored cable in trays

For offshore platforms, the preferred wiring method is type MC cable in a gas/vapor-tight continuous aluminum sheath, with an overall PVC (or other suitable material) jacket. In the Class I, Division 1 areas, conduit is the preferred wiring method.

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4.1. Materials

All sizes of conductors shall be stranded annealed copper. Tin plated copper shall be used in corrosive environments, such as salt or H_2S atmospheres.

4.2. Cable Requirements

- Multiple conductor or multiple paired cables, when installed, shall have at least 10 percent spare wires.
- AC and DC conductors shall not be run in the same cable.
- Wires that form part of intrinsically safe circuits shall be run in dedicated cables and not be mixed in the same multicore cable with other wires for power and non-intrinsically safe circuits. These dedicated cables shall, as a minimum, have an overall shield. The outer sheath shall be light blue for ease of identification.
- Intrinsically safe wiring shall be separated from non-intrinsically safe wiring and AC/DC power wiring in enclosures, raceways, or cable trays, in accordance with ISA RP12.6.

4.3. Conductor Sizes

Conductor sizes shall not be less than those specified in the following paragraphs. Where metric sizes are quoted, the nearest equivalent AWG size is given. Larger sizes than the minimum may be needed depending upon voltage drop, current capacity, impedance matching and available driving voltage. Wire selection shall be based on engineering methods and factors found in API RP 552, Sections 6 and 7.

4.4. DC Power Supply

DC power supply used for IS circuits shall not be used as a DC power source for circuits that are not intrinsically safe.

4.5. Data Communication Cables

Data communication cables for digital signals shall either be specified by the equipment manufacturers and approved by Mobil, or otherwise as indicated in the job specifications. Shielding is required for all data cables that use twisted pair or individual copper conductors.

4.6. Fiber Optic Cable

Fiber optic cable has been used for data highways. Its use in the transmission of instrument signals shall be considered. Its immunity to electrical interference, protection from damage due to lighting strikes, its potential use in hazardous locations and its unlimited bandwidth made fiber optic cable an attractive choice.

4.7. PVC Installation

Polyvinyl chloride (PVC) insulation is specified as the minimum requirement for all cable and wire insulation. PVC insulation usually satisfies all electrical, mechanical and environmental requirements and is usually available and economical in the types required for instrument wiring.

The minimum requirements for armored cables are:

- Core insulation: PVC
- Inner sheath: PVC
- Armor: Galvanized steel wire, steel tape, braid or corrugated aluminum sheath construction, depending on application and code requirements
- Outer sheath: PVC (sunlight resistant)

4.7.1. Other Insulating Materials

Other insulating materials such as high-density polyethylene or polyamide may be used with Mobil approval.

4.7.2. Hazardous Locations

- Continuous, impervious type Metal Clad (MC) cables shall be used in hazardous locations, as applicable.
- Cables shall be designed to neither propagate fire nor assist in the development of flame (flame-retardant). They shall also be designed to minimize the hazard of smoke and toxic gas given off by the cable materials in a fire. Where applicable, cables shall withstand more stringent requirements as dictated by local codes and project specifications.
- Specified cable circuits shall utilize cable constructions that allow continued electrical performance (functional integrity) under sustained (15 minutes minimum) exposure to flame or they shall be fireproofed in accordance with MP 70-P-05. Typical applications are critical shutdown loops, fire and gas detection circuits, public address systems, process isolation motor operated valves and emergency alarm and shutdown systems.

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4.7.3. Control Signals

Wire pairs for control signals shall be consistent throughout a project and, for expansions, shall match the colors in the existing plant. White (positive wire) and black (negative wire) pairs for multipair and single-pair cables are recommended.

4.7.4. Labeling

All wiring shall be clearly labeled. All conduits and cables shall have engraved stainless steel nameplates, attached at their origination and termination points. All tags shall be located so that they do not interfere with maintenance or electrical operation. Individual wires shall be labeled with sleeve type wire markers.

4.7.5. Other Requirements

- Each cable shall have 20 percent spare pairs or two spare pairs, whichever is greater.
- Cables for nonincendive circuits shall meet the requirements of ISA S12.12.

4.8. Field Wiring

Standard signal conductors shall meet the requirements of NFPA 70, Article 725, for Class 3 circuits using power limited tray cable (PLTC). This cable shall meet the test requirements of UL 1424 or other more stringent local codes. Conductor sizes smaller than No. 20 AWG shall not be used.

4.8.1. Single Pairs

- Single pairs shall be seven-strand No. 16 AWG annealed copper conductors with PVC insulation. The pairs shall be twisted six times per 305 mm (12 in) minimum and each pair shall have a 100 percent coverage, electrostatic shield with tinned copper drain wire.
- The overall jacket shall be PVC. Installed single pairs shall include a minimum of 10 percent spare pairs in each conduit, duct or tray.

4.8.2. Multicore Pairs

- Multicore cable pairs shall be twisted two times per 305 mm (12 in) minimum with individual shields.
- The cable shall have an overall electrostatic shield giving 100 percent coverage and a tinned copper drain wire.
- Pairs shall be numbered for identification within the cable.

- Discrete signals may not require the twisted pairs to be shielded. Analog and digital signals shall not be mixed in the same cable.

4.8.3. Color Coding

- Color coding shall be effected by solid contrasting colors and be consistent between single pairs and pairs in multipair cables.
- White or red wires are preferred to indicate positive polarity and black is preferred to indicate negative polarity.
- Note: Polarity color coding has not been consistent through the industry or within Mobil. Its practice shall be resolved in terms of local codes, existing color coding and owner preference.

4.8.4. Special Cables

Where special cables are required (for example, for pH sensors, flames scanners and other high impedance sensors), the vendor's recommended cable shall be used.

4.8.5. DC Power Supply

DC power supply wiring shall not be run in the same multicore cable as signal wires.

4.8.6. Analog Signal Conductors

Analog signal conductors installed in cables trays or troughs shall meet the requirements of NFPA 70, Article 725, for Class 3 circuits using power limited tray cable (PLTC).

- Single-pair cable for analog and digital measurement and control signals shall have seven-strand 1.5 mm^2 (No. 16 AWG) annealed copper conductors with PVC insulation.
- Wire pairs shall be twisted a minimum of six times per 300 mm (12 in) and shall have a 100 percent coverage shield (electromagnetic screen) with a tinned copper drain wire.
- The overall outer sheath shall be PVC.

4.8.7. Thermocouple Extension Wire

- Thermocouple extension wire shall meet the requirements of NFPA 70, Article 725, for Class 2 and Class 3 circuits using PLTC.
- Single-pair thermocouple extension wire shall have solid 1.5 mm^2 (No. 16 AWG) alloy or copper conductors with PVC insulation.

- The pairs shall be twisted a minimum of six times per 300 mm (12 in) and shall have a 100 percent coverage shield (electromagnetic screen) with a tinned copper drain wire.
- The overall sheath shall be PVC.
- The standard limit of error for thermocouple extension wire shall meet the requirements of ISA MC96.1.
- Color coding of thermocouple extension wire shall conform to ISA MC96.1.
- Thermocouple extension wires exposed to high temperatures, ranging from 80–204°C (176–400°F), shall be Teflon insulated with a Teflon outer sheath. Single-pair wire shall be used only.
- Where practical, transition through high-temperature areas shall be by extended length, mineral insulated, metallic sheathed (stainless steel) thermocouples.
- This is normal practice and is required for gas turbines.

4.8.8. Field Wiring in Conduit

- All field wiring in conduit shall have an outer sheath in addition to the conductor electrical insulation. Single wires, bundles of wires or unsheathed pairs shall not be used in raceways.
- Multipair and multiconductor cable used in the field between junction boxes, panels and equipment shall conform to Section 5.3.

4.9. Homerun Cables

4.9.1. Conductors for Analog Signals

- As a minimum, conductors for analog signals in multipair cables shall be seven-strand 0.5 mm^2 (No. 20 AWG), annealed copper with PVC insulation.
- The pairs shall be twisted a minimum of two times per 300 mm (12 in) and each pair shall have a 100 percent coverage shield (electromagnetic screen) with a tinned copper drain wire.
- Pairs shall be numbered a minimum of every 75 mm (3 in) for identification within the cable.

4.9.2. Conductors in Multiconductor Control Cables

- As a minimum, conductors in multiconductor control cables for power-limited applications shall be seven-strand 1.5 mm^2 (No. 16 AWG), annealed copper with PVC insulation.

- The overall jacket shall be PVC.
- Wires shall be numbered every 75 mm (3 in) for identification within the cable.
- Color coding shall not be a substitute for numbering.

4.9.3. Conductors in Multipair Thermocouple Extension Cables

- As a minimum, conductors in multipair thermocouple extension cables shall be solid 0.5 mm^2 (No. 20 AWG), with color coded PVC insulation.
- The pairs shall be twisted two times per 300 mm (12 in) and each pair shall have a 100 percent coverage shield (electromagnetic screen) with a tinned copper drain wire.
- Pairs shall be numbered every 75 mm (3 in) for identification within the cable.

4.10. Cross Connections and Interconnections

4.10.1. Cross Connection

- Cross connection single-pair cables within marshalling areas shall be twisted two times per 300 mm (12 in).
- An electromagnetic shield and an outer sheath are not required.
- Factory numbering is not required.
- Both ends of pairs shall be tagged (heat shrink tubing label) with a loop number.
- In general, wiring contained entirely within a single enclosure shall not require an outer protective sheath.

4.10.2. Interconnection

- Interconnection (between marshalling areas, from marshalling areas to input/output cabinets, between input/output cabinets, etc.) single-pair, multipair and multiconductor cables shall have protective outer sheaths.
- An electromagnetic screen is not a general requirement; however, all routing of interconnection wiring shall be evaluated for potential signal degradation resulting from adjacent electromagnetic energy sources.
- As a minimum, wiring between enclosures shall require an outer protective sheath.

4.10.3. Conductors

- As a minimum, conductors for cross connections and interconnection wiring shall be seven-strand copper 1.5 mm^2 (No. 16 AWG) for single-pair cables and 0.5 mm^2 (No. 20 AWG) for multipair cables.

4.11. Digital Communication Cables

Twisted pair cable for digital communication shall be specified and/or approved by the digital equipment supplier.

4.11.1. Coaxial Cable

- Coaxial cable for digital communication shall be specified and/or approved by the digital equipment supplier. Where transmission distance exceeds the digital equipment supplier's specification, the cable size shall be increased to reduce line loss with Mobil approval.
- Coaxial (electronic) cables shall be shielded from electronic interference.
- Aerial installations are not recommended for electronic transmissions.

4.11.2. Fiber Optic Cables

In general, fiber optic cables shall be in accordance with the recommendation of the manufacturer(s) supplying the receiving and transmitting equipment.

- Where competitive bidding may apply, the equipment supplier specifying the cable shall provide a specification that includes bandwidth, attenuation, index of refraction and core size.
- Fiber optic cables shall have 50 percent spare fibers or four spare fibers, whichever is greater.

4.11.2.1. OTDR

Optical fiber cables shall be tested for integrity and cable length using an optical time domain reflectometer (OTDR). Cables shall be tested on the reel before installation and when installed and terminated. All fibers, including spares, shall be tested.

4.11.2.2. Attenuation Test

An end-to-end attenuation test to calculate optical power loss shall be performed after installation is complete. This test shall encompass all elements (fiber, connectors and jumpers) that shall make up the complete fiber optic link.

4.11.2.3. Redundant Paths

Optical fiber cables, when used for redundant paths, often require a cable length for one of the redundant paths in excess of cable route distance for transit time equalization. Where fire code or available space prevents the use of excess cable from being coiled in building wireways, store coiling in a special purpose box located just outside the building. As an alternative, loop the cable within the cable tray using expansion sections at the loop points.

4.11.2.4. Splicing

- Fiber optic cable routing, cable support and protection systems shall be chosen and engineered to preclude the need to splice cables. Where splicing is unavoidable, a splice box at grade shall be used. All splices require Mobil approval at each stage of engineering and construction.
- Splice/interconnect enclosure shall be used for transition between outdoor and indoor fiber optic cable. The enclosure shall be located at the nearest, convenient point to the entry of the outdoor cable.

4.11.3. Thermocouple Extension Wire

- The preferred method for thermocouple transmission, from the process area to the control room, is to install a 4-20 mA temperature transmitter over a single twisted pair wire.
- An alternate method requires that all thermocouples within a specific area be wired using thermocouple extension wire terminated to a field multiplexer having a temperature compensating junction.
- Sensor outputs are then multiplexed to the control room/equipment room by a single twisted pair.
- Thermocouple extension wire, when used, shall incorporate a continuous pair of thermocouple extension wires from the thermocouple head to the receiver instrument. Where this method is impractical or uneconomic, Mobil approval for use of other methods is required.
- Thermocouple extension wire shall meet the requirements of NFPA 70, Article 725, for Class 2 or Class 3 circuits using PLTC. This cable shall also meet the test requirements of UL 1424 or other more stringent local codes.
- Thermocouple extension wires in high ambient temperatures shall be Teflon insulated with Teflon jackets. Only single pairs shall be used.

4.11.4. Additional Requirements

- Color coding shall conform to ISA MC96.1.
- The standard limit of error shall also meet the requirements of ISA MC96.1.

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- Instrumentation DC power and control wiring shall meet the requirements of NFPA 70 and be sized to deliver proper voltage levels to instrument and control equipment.
- Single conductors and/or twisted pairs pulled in bundles through conduit shall be No. 14 AWG (minimum) for all control voltages.
- Multiconductor cables shall use No. 16 AWG, minimum.
- All conductors shall be stranded. Tin plating shall be required in corrosive atmospheres.

5. Entries / Terminations

5.1. Control Room Entries

- In order to prevent gas migration into buildings, all instrument cables originating from field devices shall be terminated in at least one vented junction box, prior to entering the control room/equipment room.
- All cables in conduit entering the control room/equipment room (regardless of area classification) shall be sealed at the point of entry outside the building with a vapor seal, in order to protect against environmental factors (rain, moisture and insects).
- All entries shall be designed to prevent moisture from entering instrument termination areas. Conduit shall have lowpoint drains and enter the terminal box from below. Top entries are not permitted.
- Side entry is permitted for termination boxes. A weatherproof hub with an O-ring seal shall be used for bottom and side entry, unless a more stringent barrier gland is required.

5.2. Field Instrument Connections

Field instrument terminal boxes are small enclosures, close coupled to field instruments such as transmitters, solenoid valves and process switches.

5.2.1. Terminal Strips

- Terminal boxes shall have integral terminal strips.
- Wire nut connections and butt splices between any instrument and connection pair shall not be used.
- Terminal boxes shall be approved for the area classification.

- Where separate terminal boxes are used, boxes shall be close-coupled to the field instrument.
- Terminal strips shall be factory mounted or mounted in the field in predrilled and tapped holes. Terminal boxes for explosion-proof service shall not be modified in the field.

5.2.2. Seals

- External explosion-proof seals shall be installed in a manner that ensures removal of the instrument without having to break this seal.
- Any sealing compound used shall comply with NFPA 70, Article 500.
- Double seals shall be required and installed for process instruments as described in NFPA 70, 501-5(f)(3). Refer to Figure 4.8 F of API RP 14F.
- When required, explosion-proof seals shall be close-coupled to the instrument.
- Armored cable or flexible metal conduit shall be used to connect field instruments to terminal boxes or rigid metal conduit. Flexible metal conduit shall be aluminum or steel and plastic coated in accordance with the job specifications.
- A liquid-tight, flexible metal conduit shall be used to connect the instrument/terminal box/seal combination to rigid steel conduit. As a minimum, this flexible conduit shall have a 914 mm (36 in) length and a 300 mm (12 in) slack to facilitate positioning and removal of instruments. Flexible conduit in excess of 1500 mm (60 in) requires Mobil approval.

5.3. Field Junction Boxes

Wiring from field devices (single pair or triad cables) normally terminates at strategically placed junction boxes, from which the signals are carried via multicore cables to the control room/equipment room. There are exceptions, however, where direct entry cable may be required.

- Junction boxes shall be NEMA 4X (preferred) or NEMA 7 if required by NFPA 70, Article 500.
- Junction boxes shall have breather drain plugs or ventilators, unless otherwise stated in the job specifications.
- A minimum of 10 percent spare terminals shall be provided in field junction boxes. The contractor shall terminate all instrumentation wiring, including all spares, so that no spare wire is coiled and taped. Terminal blocks shall be provided for terminating spare wires and for the purpose of carrying shields through the boxes, without grounding them.

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5.3.1. Safe Wiring

Intrinsically safe wiring shall be separated from non-intrinsically safe and shall not be marshalled in the same junction box. It shall be designed and installed in accordance with ISA RP12.6 and NFPA 70, Article 504.

5.3.2. Sizing

- The size of the junction box shall be sufficient to allow for ease of installation and maintenance.
- It shall be large enough to allow for additional cable or conduit penetrations.
- No terminals shall be mounted within 51 mm (2 in) of the edge of the back panel.
- A minimum of 102 mm (4 in) clearance shall be maintained on either side of the terminal blocks.

5.3.3. Terminal Strips

- Terminal strips in field junction boxes shall be of modular construction.
- The terminal strips shall have separate connections available for jumpers or test leads.
- All screws and parts shall be captive.
- For corrosive and offshore environments, the junction bar, clamps and screws of the terminal blocks shall be corrosion resistant (surface treated).
- Electrical contacts shall be of the pressure plate type, with all live parts recessed into the insulated block.
- Terminal blocks shall be spaced a minimum of 6–8 mm ($^{1}/_{4}$–$^{5}/_{16}$ in) apart.
- Terminals and terminal strips shall be clearly numbered.

5.3.4. Terminal Screws

Terminal screws shall have integral lock washers as a minimum or else tension designed construction equivalent to a lock washer.

5.3.5. Ferrules/Crimping

- All conductors constructed of stranded wires can be terminated using ferrules mounted over the strands.
- The insulation of the wires shall be maintained up to the ferrules.

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- The outer sheath of the cable shall be removed only as far as is necessary to make a satisfactory installation.
- Ferrules shall be crimped using a pre-torqued crimping tool, suitable for crimping/ferrule use.
- These requirements shall prevent gradual withdrawing of cores from the crimp/ferrule.
- The contractor shall supply two crimping tools used to crimp wire tips from AWG 11-20.
- All unused cores and screens shall be terminated to spare terminal blocks as approved by Mobil.

5.3.6. Stainless Steel Construction

Field junction boxes in Class I, Division 2 and unclassified locations for measurement and control circuits shall be constructed from welded austenitic stainless steel sheet, have stainless steel hardware (hinges, clasps, screws, etc.) and meet the requirements of NEMA 4 (IP54).

5.3.7. Explosion-Proof Boxes

Explosion-proof junction boxes, when required, shall be corrosion-resistant, copper-free aluminum or iron alloy.

5.3.8. Breathers and Drains

- Field junction boxes used with conduit or armored cables systems, shall have breathers (vents) and drains where NEMA 3 (IP53) classification satisfies the installation location.

  NOTE: The addition of breathers and drains reclassifies NEMA 4 (IP54) enclosures to NEMA 3 (IP53).

- For NEMA 4 (IP54) classification (shall be watertight during hosedown or other conditions of splashing water are not permitted), all conduit and cable ends shall be sealed with epoxy to reduce the possibility of gases and vapors passing from classified areas to nonclassified areas.
- Refer to Section 6.3 of this Practice for further discussion.

5.3.9. Entrance

- Conduit or cable shall not enter through the top of field junction boxes.
- Side entry shall be used only after bottom entry possibilities are exhausted.
- All conduit coming from locations above the junction box shall have a low-point drain adjacent to the junction box.

5.4. Remote Instrument Enclosure Entries and Terminations

As a minimum, conduit and armored cable entries into pressurized unclassified locations shall have conduit seals or cable glands to reduce loss of enclosure pressurization. Additional sealing methods, such as fanning and sealing or fanning and venting of conductors in multiconductor cables before entering the RIE, control room or other unclassified building, shall be determined for the specific installation in accordance with Section 6.3 of this MEP.

5.4.1. Termination Cabinets

Unless otherwise stated in the job specifications, all wiring that interfaces to the control room/equipment room shall first terminate within field termination cabinets.

- Separate termination cabinets are required, in order to eliminate any need for direct field connections to be made to a pre-tested system. These cabinets allow for field wiring schedules to be maintained, in the event the system is delivered late.
- For intrinsically safe wiring, the field termination cabinets shall house intrinsically safe barriers. Spare wiring shall terminate to dummy barriers.
- For non-intrinsically safe wiring, the field termination cabinets shall house terminal blocks. All spare wiring shall terminate to terminal blocks.

Each termination cabinet shall be provided with any or all three of the following tin-plated copper grounding buses, 6.3–25.4 mm ($^1/_4$ x 1 in) minimum.

1. Non-IS instrument signal ground
2. IS instrument signal ground
3. Equipment ground

5.4.2. Ground Buses

- The ends of the ground buses shall be arranged so that when all sections of the field termination cabinets are in place, each grounding bus shall be one continuous system.
- After installation, the grounding buses shall be bonded to the instrument grounding system at only one point.
- Instrument cases shall not rely on grounding through the steel of the panel.

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6. Mechanical and Fire Protection of Wire and Cable

6.1. Mechanical Protection

Armored cable may be fastened to open trays and generally may be exposed to ordinary facility operations and maintenance activity.

In general, all wire and cable shall be externally or inherently protected from damage by a metal covering (100 percent). Where non-armored cable is run in open trays, on ladders or in channels that do not provide a 100 percent metal protection, Mobil approval is required.

The following protection is required for wire and cable:

1. Abovegrade installations shall be protected from damage by normal plant operations with an external or integral metal cover. Rigid steel or rigid aluminum conduit is recommended per MP 33-P-23. Where local codes and practices allow, metal-clad cable in an approved cable tray may be used.

2. Belowgrade installations are protected from damage by normal plant operations and from damage by other operations (for example, backhoes and augers) when totally enclosed in red colored concrete troughs. Metal cladding alone does not provide complete protection against accidental intrusions by digging equipment. Risk and cost comparisons shall be made whenever cable is buried without concrete encasement.

3. Wire and cable in buildings shall be protected from damage and disturbance by all activities, such as preventive maintenance, troubleshooting, system additions, etc. Refer to NFPA 70 for wiring methods.

4. Digital communication cables shall be protected from damage by the methods addressed in Items 1 and 2 above. Communication cables may be routed in a covered tray along piperacks outside battery limits. Fiber optic cables may be (aerial) strung on messengers (Kevlar rope) between dedicated reinforced concrete poles.

6.2. Fire Protection

Critical cable circuits shall use cable constructions that have a continued electrical performance (integrity) under fire conditions or they shall be fireproofed in accordance with MP 70-P-05.

Unless modified by the job specifications, the following shall be considered critical circuits:

1. Critical control loops (instrument loops that are necessary to effect safe shutdown and control of processes and equipment while exposed to a fire)

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2. Fire and gas equipment while exposed to a fire
3. Fire and gas detection circuits
4. Public address and emergency alarm systems
5. Fire protection systems, such as deluge valves, sprinkling systems, CO_2 release, etc.

6.2.1. Insulation

Insulation to reduce risk of fire loss shall be per MP 70-P-01 and MP 70-P-05.

1. In general, field wiring (junction box to instrument) does not require protection from fire; however, routing of field wiring shall be designed for minimum exposure to fire risk areas and wiring in critical service shall be fire protected to remain operational for a minimum of 15 minutes under continuous exposure to flame. Concentrations of field wiring within process units is not recommended even when fire protected.
2. Homerun cable shall not be located in fire risk areas.
   - Belowgrade installation greatly alleviates fire risk; however, the location of field junction boxes that terminate homerun cables require careful selection to maintain a low fire risk.
   - Where fire risk to a field junction box cannot be ruled out by location, fire insulation and other protection methods shall be used. Installation of FJBs that terminate homerun cables inside battery limits is not recommended.
   - Where homerun cables in conduit or tray (typically multipair cables) are necessary within the process battery limits, these cables shall first terminate at battery limits in the primary FJB. Subsequent routing of the multipair shall be from this FJB to an intermediate field junction box (IFJB) inside the process battery limits.
3. Wire and cable in buildings (RIE and control rooms) are subject to the fire codes and fire suppression protection required for buildings containing electrical equipment. Fire protection by insulation of wires or other methods is not required.
4. Digital communication cables shall be protected from fire by routing only in fire safe areas. Redundant paths of communication cables shall be chosen to preclude simultaneous fire risk to both paths.
5. Homerun cable shall have 2 m (6 ft) of excess length coiled underground beneath junction boxes in fire risk locations. This facilitates reconnection of clean cable in the event of fire damage.

6.3. Prevention of Gas and Vapor Passage in Cables and Raceways

Vapor and gas sealing (prevention or minimization of migration of gases and vapors from classified to unclassified areas) of conduit and cables shall be addressed depending on the circumstances. NFPA 70, Section 501-5, describes the purpose and methods of sealing to minimize gas and vapor passage between classifications. The guaranteed effectiveness of sealing alone is qualified in Section 501-5, FPN No. 1 as quoted below:

> "Seals are provided in conduit and cable systems to minimize the passage of gases and vapors and prevent the passage of flames from one portion of the electrical installation to another through the conduit. Such communication through Type MI cable is inherently prevented by the construction of the cable. Unless specifically designed and tested for the purpose, conduit and cable seals are not intended to prevent the passage of liquids, gases or vapors at a continuous pressure differential across the seal. Even at differences in pressure across the seal equivalent to a few inches of water, there may be a slow passage through the seal and through conductors passing through the seal. See Section 501-5(e)(2). Temperature extremes and highly corrosive liquids and vapors can affect the ability of seals to perform their intended function. See Section 501-5(c)(2)."

6.3.1. Elimination of Pressure Differential

The principle consideration for preventing the flow or migration of vapors and gases from classified locations to unclassified locations is elimination of pressure differential between the locations that would tend to cause flow from the location where hazardous gases, vapors or liquids are present (classified) to the unclassified location. The following design steps, as a minimum, shall be used:

1. The junction box or enclosure in the classified location that terminates the cable or conduit leaving the classified area shall be vented to atmosphere.
   - Where feasible, these junction boxes shall be installed in noncorrosive locations.
   - If the enclosure is installed in a location where corrosive gases may be present, the enclosure shall be purged with instrument air. The purge rate (10 cc/min nominal) and vent size shall preclude the possibility of pressure buildup in the enclosure. This purge is for reducing the corrosive gas concentration in the enclosure and shall not be confused with purging (Class Z) for hazard reduction.
   - Where environmental conditions include hosedown practices or splashing water, breathers and drains shall not be used and the cable ends shall be sealed with epoxy to reduce the possibility of gases and vapors passing from the classified area to the nonclassified area.

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2. The unclassified building or enclosure terminating the homerun cable shall be purged and pressurized per NFPA 496.
3. All junction boxes and enclosures in classified locations, including explosion-proof boxes, shall be vented to atmosphere.
4. Cables leaving Division I locations shall have interstitial sealant or be certified as impervious to gas passage, such as Type MI cable.
5. Cables that have large interstitial openings shall have these openings blocked with sealant to reduce air loss in pressurized buildings and enclosures.
6. Conduits shall be sealed per NFPA 70.

7. Belowgrade Installations

Direct burial cable may be used, with Mobil approval. Underground splices shall not be permitted. If splicing is unavoidable, this shall be done above ground in a splicing box.

7.1. Types of Belowgrade Installations

- Direct Burial with Protective Tiles: Cables laid in an earthen sidewall trench, backfilled with sand and protected and identified with red concrete tiles.
- Direct Burial in Covered Concrete Trough: Cables laid in a preformed or poured-in-place reinforced red concrete trough filled with sand and covered with a reinforced concrete slab or individual reinforced concrete covers. The trough may be at grade (top of slab even with grade) or belowgrade (refer to MP 33-P-24).
- Concrete Encased Conduit (Conduit Bank): Cables installed in metal and/or plastic (PVC) conduit that is totally encased in red concrete (refer to MP 33-P-23).

7.1.1. Direct Burial with Protective Tiles

This method (refer to Figure 1) shall be used only outside of process areas for long runs of single-purpose, noncritical control or information cable runs. Road crossings require concrete-encased conduit.

- Refer to MP 33-P-24 for details of trench design.
- Only metal-clad cable shall be used.

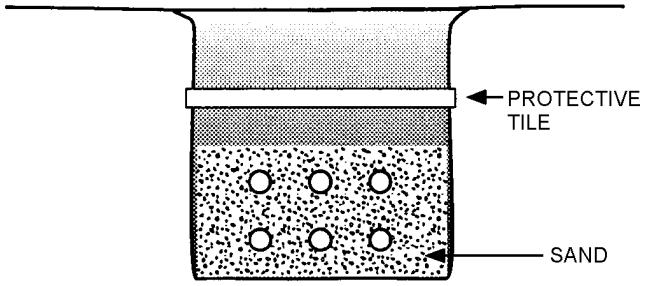

Figure 1: Direct Buried with Protective Tiles–Armored Cable Required

7.1.2. Direct Burial in Covered Concrete Trough (Below Surface)

This method (refer to Figure 2) may be used outside process areas with the exception of road crossings or other areas that preclude trench opening (in which case, concrete-encased conduit shall be used).

- Refer to MP 33-P-24 for details of trough design.
- Armor or aluminum sheath are optional for cable protected by concrete trough with concrete cover. The use of armor, aluminum sheath or other cable construction protection means shall be based on local conditions, cable exposure when leaving the trough and anticipated rough handling during construction.

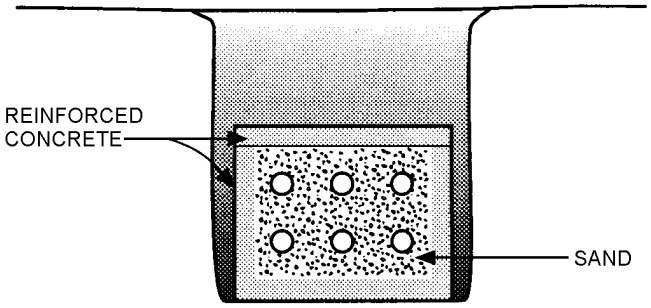

Figure 2: Direct Buried (Belowgrade) with Covered Concrete Trough–Armored Cable Optional

NOTE: Direct burial cable in a covered concrete trough provides adequate mechanical protection. The basic function of the concrete envelope is protection from damage by digging (backhoes, augers, etc.). In addition, concrete covered trough and concrete encased conduit are equal in consideration in wet (hydrocarbon and/or water) environments.

7.1.2.1. Disadvantages

Disadvantages of direct buried cables in concrete troughs below surface include:

- Cable troubleshooting and cable addition is difficult.
- Cable damage (open circuits/short circuits/grounds) during construction is usually not discovered until after the installation is completed.
- Construction coordination in proximity to process units is problematic, since the entire or major portions of the trough installation shall be worked at the same time and all cables fully or partially handled prior to covering the trough.

7.1.2.2. Advantages

Advantages of direct buried cable in concrete trough include:

- Higher density of cables for same overall encasement cross-section compared to conduit bank.
- All preformed concrete sections may be used.
- Conduit, conduit fittings, conduit spacers and concrete forms are not required.

7.1.3. Direct Burial in Covered Concrete Trough (At Surface)

This variation on installation of direct burial cable in concrete troughs (refer to Figure 3) is used in process areas and has the following advantages and disadvantages:

- Cables may be replaced or added.
- Covers shall be sealed against liquid hydrocarbon spills.
- Covered concrete trough (at surface) shall not be used in heavy equipment traffic areas unless the cover and trough are specifically designed to handle the equipment loadings.

Refer to MP 33-P-24 for details of trough design.

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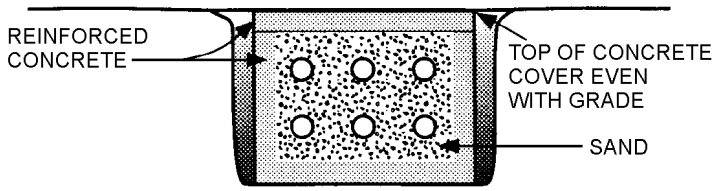

Figure 3: Direct Buried (At Grade) with Covered Concrete Trough–Armored Cable Optional

7.1.4. Concrete-Encased Conduit (Conduit Bank)

Conduit encased in concrete is the recommended method for routing homerun cables from process units to the RIE housing the controls for that process unit.

Construction requirements for conduit bank design are covered in MP 33-P-23.

7.1.4.1. Advantages

Advantages of concrete-encased conduit include:

- Sections of conduit bank (road crossings) may be fully installed and backfilled before any cable is installed.
- Spare conduit may be used for installation of future cable.
- Damaged or incorrect cable may be pulled out of conduits and replacement cables installed at any time.
- Cables are installed in one conduit at a time from areas that can be protected from other construction activities.
- Conduit banks can be installed in the early stages of the project.

7.1.4.2. Disadvantages

Disadvantages of concrete-encased conduit are mostly economic and become apparent when pull points are required for long runs having several bends. Obtaining estimates and including quotes by local installation contractors comparing the costs of direct burial to encased conduit is recommended.

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8. Abovegrade Installations

8.1. Process Units

Rigid steel or aluminum conduit per MP 33-P-23 is recommended inside process units. Metal-clad cable is an acceptable alternate where the local practices and construction experience exists for metal-clad cable.

Routing and supporting of metal-clad cable shall be by dedicated trays. Metal-clad cable shall not be supported or routed on utility piping, process piping or structural beams.

8.2. Buildings

- All wiring shall be in accordance with NFPA 70.
- Signal and communication wiring internal to the cabinet room or running between rooms in the same building, shall be in a cable tray above cabinets or beneath computer floors. Wire and cable shall not be run in normally occupied areas.
- Optical fiber or coaxial cables shall be enclosed in a distinctive (bright color), nonmetallic flexible conduit and where practical, segregated from other cables and potential hazards.

Modifications to API RP 552

3.2.c. Addition: Design Consideration for Transmission Systems

Pertinent international, national and local codes for the protection of sensitive electronic equipment against extraneous electromagnetic and radio frequency radiation shall be specified. Examples are:

- IEC 801-2 and 801-3: Electromagnetic Compatibility for Industrial Process Measurement and Control Equipment
- EN-50081-1: Generic Emissions Standard Part 1 for Residential, Commercial and Light Industry
- EN-50082-1: Generic Immunity Standard Part 1 for Residential, Commercial and Light Industry
- EN-50081-2: Generic Emissions Standard Part 2–Industrial
- EN-50082-2: Generic Immunity Standard Part 2–Industrial
- United Kingdom EMC Regulations Statutory Instrument No. 2372 of 1992

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- It is mandatory for almost all electrical and electronic equipment supplied or installed in European Economic Community countries to carry European conformity marking (CE) for conformity with Council Directive 89-336-EEC, July 3, 1989 on the approximation of the laws of the member states relating to electromagnetic compatibility.

3.6. Modification: Digital Fieldbus

Mobil approval shall be obtained prior to consideration of any Fieldbus application. Current Foundation Fieldbus standards shall be followed.

5.3. Table 3. Modification: Wire Separation

The minimum separation between signal wires and power wires shall be as follows:

Power Wiring System Volts (Nominal)	Minimum Separation (mm)
Up to 125 or 10A	300*
125 to 250 or 50A	500*
250 to 500 or 200A	750*
Over 500 to 5KV or 500A	1250
$1^{1}/_{33}$ KV or 800A	4000

Where local spacing codes are more stringent, those codes shall govern. (* A preferred spacing of 1 m (3 ft) is recommended wherever practical.) When instrument signal cables cross power cables, they shall do so at 90 degrees while applying the above separation.

If it is not practical to apply the above separation for cables in trenches (for example, where instrument signal cables cross very high-voltage power cables), cross the power cables at 90 degrees and at the maximum practical separation. Run the instrument cable through a piece of steel pipe with 1 m (3 ft) overlap on either side of the crossing. Ground the piece of pipe locally with a 21 mm^2 (No. 4 AWG) length of insulated (PVC) conductor to a ground rod(s) close to the pipe. Prove by test that the earth resistance is less than one ohm.

6.1.2. Addition: Mixing Signals

IS and non-IS signals shall not be contained within the same cable or marshalled in the same field junction box. IS and non IS wiring may be run in the same tray or trench providing they are separated and clipped in two appropriate bundles as far apart as possible. At least one category shall be armored; otherwise, a physical tray or trench partition must be used.

6.1.4. Modification: Grounding

Grounding of signal and intrinsically safe circuits shall be at one point only. The quality of that ground shall be such that the total earth resistance is less than one ohm. This shall be proved by test and subject to Mobil inspection.

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Shields (screens) shall be grounded to the signal ground bus in the RIE, not in the field. Signal conductors shall be grounded to the signal ground bus when grounding is required. Refer to MP 32-P-01 and MP 32-P-05.

6.4.1. Modification: Grounding

Floating thermocouple circuits shall be used and the extension wires shall not be grounded. Extension wire shields shall be grounded at one point only, usually at the control room, signal, ground bus. Grounded thermocouple tips require Mobil approval and, when these are used, the shields of the extension wire shall be grounded at the thermocouple head only.

The material of the extension wire conductors shall be the same as that of the associated thermocouple. For example, a Type K thermocouple shall use a Type K extension wire.

7.4. Addition: Temperature Rating

Ambient temperature limits for signal and control wire are:

- A maximum of 80°C (176°F) for installation
- A minimum of 5°C (41°F) for storage
- A minimum of -9°C (15°F) for pulling

13.1. Modification: Locations and Advantages

Metal-clad cable shall be used in cable trays or in ducts.

13.2.7. Modification: Fireproofing

Where trays are routed through fire-risk areas, they shall be fireproofed in accordance with MP 70-P-05.

13.2.6. Modification: Routing

Wire and cable shall be routed a minimum of 5 m (15 ft) above exchangers and pumps and a minimum of 3 m (10 ft) laterally from pumps, exchangers and furnace walls.

14.3.1. Addition: Conduit Materials and Installation

Splices shall not be permitted without Mobil approval.

17. Addition Wiring for Field Mounted Process Instruments

Wire pairs shall be terminated on adjacent terminals. Shield drain wires (screens) shall be terminated on terminals adjacent to those of the respective wire pairs. Cable shields (screens) or drain wires shall not be used as conductors.

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17.3. Addition: Temperature

Thermocouple junction box (head) heat protection shall be provided if there is a possibility that the head temperature may exceed 50°C (120°F). The number of extension wire terminals in the field shall be minimized.

18.3. Addition: Box Design

Weatherproof conduit fittings shall have a minimum of three conduit hubs. Covers shall be secured with lever-type fasteners (Crouse-Hinds Condulet Form 7 or equal). Covers fastened with screws through tapped holes in the body are not acceptable (Crouse-Hinds Condulet Form 8, for example).

19.2. Addition: Field Wiring Terminations

When terminated in pressure plate terminal blocks, stranded wire conductors shall meet the terminal block manufacturer's specifications for size of wire, stripping length and torque. For measurement and control input/output loops, one wire only shall be terminated under a terminal block pressure plate. Where there are multiple wires being connected together (such as shields, power commons or circuits with complex connections), the terminal strip manufacturer's jumper bars or strips shall be used wherever possible. In any case, no more than two wires (and always the same type and size of wire) shall be terminated under the same pressure plate.

20.7. Addition: Grounding of Cable Shields

Cable armor shall be grounded at one point only either at the Junction box or at the RIE/Control room entry point.

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Transmission Systems

MP 32-P-03

July 1998

Scope

This Mobil Engineering Practice (MEP) covers the basic requirements for the design, installation and testing of instrument transmission systems including transmitters and receivers.

Table of Contents

Scope **1**

1. References **4**

1.1. MEPS–Mobil Engineering Practices 4

1.2. API–American Petroleum Institute 4

1.3. IEC–International Electrotechnical Commission 4

1.4. Additional References 4

1.5. Miscellaneous 4

2. General **5**

3. Modifications to API RP 552–Transmission Systems **5**

Modifications to Section 4 ..... **5**

Modifications to Section 6 ..... **6**

Modifications to Section 7 ..... **7**

Modification to Section 9 ..... **7**

Modification to Section 14 ..... **8**

Modification to Section 18 ..... **8**

4. Transmitters **8**

4.1. General 8

4.2. Design 9

4.3. Pneumatic Transmitters 10

4.4. Conventional (Analog) Transmitters 11

4.5. Smart (Microprocessor-Based) Transmitters 11

5. Receivers **12**

5.1. Indicators 12

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5.2. Recorders and Controllers 12

5.3. Charts and Scales..... 13

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1. References

The following publications form a part of this Practice. Unless otherwise specified herein, use the latest edition.

1.1. MEPS–Mobil Engineering Practices

MP 32-P-01	General Requirements for Instrumentation
MP 32-P-19	Instrumentation Piping and Tubing Fittings

1.2. API–American Petroleum Institute

API RP 552	Transmission Systems First Edition

1.3. IEC–International Electrotechnical Commission

IEC 60079-10 (1995-12)	Electrical Apparatus for Explosive Gas Atmospheres–Part 10: Classification of Hazardous Areas
IEC 60079-11 (1991-11)	Electrical Apparatus for Explosive Gas Atmospheres–Part 11: Intrinsic Safety 'I'

1.4. Additional References

EN 50 020	CENELEC–Comité Europeén de Normalisation Electrotechnique

1.5. Miscellaneous

"Instrument Engineers' Handbook: Process Control, Third Ed.," By Bela G. Liptak, Chilton Book Company, Radnor, PA ©1995

2. General

The design and installation of transmission systems shall be in accordance with the requirements of this MEP, Project Specifications and API RP 552, except where superceded by more stringent local regulations.

References and requirements of MP 32-P-01 shall apply to this Practice. The piping component selection shall conform to MP 32-P-19.

For more information, also refer to "Instrument Engineers' Handbook: Process Control, Third Ed.," By Bela G. Liptak, Chilton Book Company, Radnor, PA ©1995.

3. Modifications to API RP 552–Transmission Systems

The following items are amendments to API RP 552. Unless stated otherwise, the section, paragraph and figure numbers refer to those used in that standard.

Modifications to Section 4

4.3.1. Classified Areas and Listed Equipment

For guidance on Intrinsically Safe equipment for projects outside of the US, refer to the following standards:

- IEC 60079-10 (1995-12) and IEC 60079-11 (1991-11)
- CENELEC EN 50020

The following show the differences between practices in the United States and Europe.

- Zone 0: An area in which an explosive air/gas mixture is continuously present or present for long periods of time.
- Zone 1: An area in which an explosive air/gas mixture is likely to occur during normal operation.

- Zone 2: An area in which an explosive air/gas mixture is unlikely to occur, but if it does occur, only for a short period of time.

	Continuous Hazard	Intermittent Hazard	Abnormal Condition Hazard
United States	Division 1	Division 1	Division 2
IEC/Europe	Zone 0	Zone 1	Zone 3

Modifications to Section 6

6. Engineering Factors in Selection of Wire Types for Electronic Systems

Copper wires that are untwisted, unshielded, stranded shall not be used as stipulated in Table 4.

6.1.1. Substitution: Wire Type

Replace the phrase:

> "Although a pair of untwisted, shielded and stranded copper wires (Type 1) may be used to interconnect most industrial process control equipment, such use is not recommended."

With the following phrase:

> "Untwisted, unshielded, stranded copper wires shall not be used without written approval."

6.1.2. Substitution: Mixing Signals

Replace "should" to the stronger form "shall".

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6.1.3. Addition: Resistive Loading

American Wire Gauge (AWG)	mm^2
10	5.26
12	3.30
14	2.08
16	1.31
18	0.824
20	0.519
22	0.325
24	0.205

Modifications to Section 7

7.2. Substitution: Stranded Wire

Replace the phrase :

"Stranded wire is preferred…"

With:

"Stranded wire shall be used…"

7.8. Wire and Pair Identification

The individual pairs within a multipair cable shall be assigned with the tag number of the instrument. Pairs that are unused shall be tagged "SPARE".

Modification to Section 9

9.2. Signal and Power Wiring

Where power and signal cables are run in parallel trenches without the minimum separation distances, a solid barrier shall separate the cables. The signal cables shall be run in conduit that is grounded.

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Modification to Section 14

14.4. Routing

Multicore cables routed from marshalling cabinets in the Satellite Instrument House (or control building) to field junction boxes shall be underground. Above-ground installation is acceptable only when approved by Mobil.

Modification to Section 18

18.3. Junction Box Design

Junction boxes shall be made of stainless steel construction. This reduces maintenance costs over the life cycle. Signal types shall be segregated with respect to the junction box. For example, analog signals shall not be mixed with digital signals or thermocouple signals with analog signals. It is recommended that shutdown signals terminate in dedicated junction boxes where control signals are not terminated.

If fireproofing is required, junction boxes shall have fireproof insulation installed prior to field installation. The design for cable penetration into junction boxes shall be determined prior to junction box requisition.

4. Transmitters

4.1. General

All instrument loops shall consist of separate transmitter and receiver configurations. Exceptions, such as a single head for a displacement level controller or a local single-case controller, shall be subject to approval.

All instrumentation shall meet the requirements of applicable national and local codes. In addition, all instrumentation in hazardous areas shall include a certificate of compliance from a recognized agency such as FM, UL, CSA, IEC, CENELEC, etc. Any exception shall be subject to Mobil approval.

Electronic transmitters shall be equipped with either lightning or transient protection, which can either be an integral part of the transmitter or a factory-assembled external addition.

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EMI (Electromagnetic Interference) or RFI (Radio Frequency Interference) can adversely affect the performance of a transmitter or even damage it. Transmitters designed to meet standard requirements should be used in environments where EMI/RFI is expected.

4.2. Design

Transmitters shall be standardized in accordance with manufacturer and model.

- Transmitters shall be installed close coupled, if possible, adequately supported and easily accessible. Approved valve manifold shall be used. Refer to MP 32-P-19.
- The valve manifold/transmitter assembly shall be secured at the valve manifold. This will allow easy removal of transmitter for repair.
- Transmitter manifolds used in liquid seal systems shall not be furnished with bypass valve handles, unless approved.

4.2.1. Indicators

All transmitters shall have either an integral indication or a separate local indication.

- Failure or removal of the local indicator shall not interfere with the operation of the transmitter.
- Local indicators shall be furnished with integrally mounted diodes to avoid interruption of transmitted signal when taken out of service.
- Elimination of a local indicator shall require Mobil approval, and test connections shall be provided in its place.

4.2.2. Indicator Locations

Indicators shall be located so that they are readable from a normal operating walkway. For loops with control valves, indicators shall be readable from bypass valve or handwheel.

4.2.3. Transmitter Output

Transmitters shall have linear output throughout sensing range.

4.2.4. Suppressed Range

Suppressed range transmitters on critical applications, if required, shall have a redundant full range transmitter.

4.2.5. Self-Draining Transmitters

Self-draining transmitters shall be used in processes containing hazardous materials.

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4.2.6. Lightning Protection

If required, lightning protection shall be provided integral to transmitter.

4.2.7. Materials

Sensing elements and body material shall be of 316 Stainless Steel construction unless otherwise specified for processes requiring Monel or Hastelloy. Cadmium-plated carbon steel is not acceptable.

4.2.8. Factors in Transmitter Selection

The following factors shall be considered when selecting a transmitter:

- Hazardous area classification.
- Environmental factors (Ambient temperature variations, thermal radiation, humidity, dust, etc.).
- Vibration.
- Turndown.
- Reference accuracy and operating performance under environmental factors.
- Long term stability (transmitter proclivity to drift over period of time).
- Dynamic response (response time of measuring device, i.e., analog transmitter response usually faster than digital transmitter for compressor applications).
- Minimum number of transmission and power wires (e.g., two-wire transmitter versus three-wire transmitter). Transmitters shall be powered from the receiver over the same wires that are used for transmission.
- Delivery, availability, cost.

4.3. Pneumatic Transmitters

4.3.1. Output

The transmitter shall have a linear output of 20 to 100 kPa (0.2 to 1.0 bar) or (3 to 15 psig) throughout measured range.

Maximum transmission distance shall be no more than 100 m (333 ft). Exceptions shall require approval.

The transmitter shall have a 6 mm ($^1/_4$ in) tee and plugged valve for testing the output signal.

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4.3.2. Valve Construction

The tee and plugged valve shall be of material specified in MP 32-P-19.

4.3.3. Application

Pneumatic transmitters shall be used for local field applications that do not require feedback to the central control room.

4.4. Conventional (Analog) Transmitters

As a minimum, transmitters shall be of the DC current-regulating type and capable of operating with the power source located in a nonhazardous areas. These transmitters shall utilize a twisted pair two-wire system for signal/power transmission. Exceptions shall require approval.

4.4.1. Output

Conventional electronic transmitters shall have an output of 4 to 20 mA and may be used for non-critical applications. Conventional transmitters with output signals other than as mentioned above shall require approval.

4.4.2. Hazardous Area Techniques

Transmitters shall meet the hazardous area classification designated for their location. Intrinsically safe, nonincendive and explosion proof techniques may be used with approval. The technique shall be consistent with all transmitter installations in the process unit.

4.4.3. Equipment Interference

Equipment shall not be susceptible to, or interfere with, hand-held radio transceivers operated in the immediate vicinity of the equipment. Equipment shall operate in field strength of 10 V/meter over a frequency range of 27-500 Mega-Hz at a distance of 1 m (3 ft)

4.4.4. Zero and Span Adjustments

The electronic transmitter shall have noninteractive zero and span adjustments.

4.5. Smart (Microprocessor-Based) Transmitters

Smart transmitters with digital output mode signal shall be a maximum of 24 VDC and shall not used for fast response loops (i.e. compressor anti-surge control) without approval. Smart analog transmitters with 4 to 20 mA outputs shall be used for fast response loops such as compressor controls.

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Microprocessor-based intelligent transmitters are preferred for critical control applications, for the following reasons:

- Accuracy: microprocessor has self diagnosis capability
- Ease of maintenance
- Greater stability
- Less drift
- On-line configuration and remote configuration for installations in hazardous areas or inaccessible locations
- Turndown flexibility
- Bi-directional communication

Requirements stated in Section 4.4 also apply to smart transmitters.

5. Receivers

5.1. Indicators

- Local indicator gauges shall have a Type 316 stainless steel tag showing the tag number, service and range.
- Pneumatic local indicator gauges shall have as a minimum, 100 mm (4 in) dial, with the scale and spring or input range shown on the dial. Gauges shall be 20 to 100 kPa gauge (0.2 to 1.0 bar gauge or 3 to 15 psig).
- Electronic indicators shall have minimum $3\ ^1/_2$ digits and a minimum character height of 25.4 mm (1 in).

5.2. Recorders and Controllers

- Analog and digital signals from sensors shall be conditioned, if necessary, for input to any receiver display unit.
- A microprocessor-based controller or data acquisition unit shall be capable of receiving 4 to 20 mA DC, mV, and digital signals.
- The controller system shall be capable of generating the required output signal necessary to operate the final control element; that is, a valve.
- Signal conditioning can linearize flow signals, thermocouples, resistance bulbs, etc.

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5.2.1. Design Features

Recorders shall have the following design features:

- A maximum of three pens
- Disposable ink cartridges for pens
- A chart speed not less than 19 mm ($^3/_4$ in) per hour for strip chart types

5.2.2. Field-Mounted Multiplexers

Field-mounted multiplexers may be used for transmission of temperature points for indication in the central control room.

5.3. Charts and Scales

- Scales for control room or local indicators shall be direct reading for pressure and temperature.
  - Flow indicators shall be direct, linear or zero to 10 square root, depending on the application.
  - Level indication shall be direct reading or zero to 100 percent uniform.
- The use of charts shall be minimized. Preference shall be given to microprocessor based charting systems. Charting and trending technology on the DCS systems shall be maximized.
- Charts shall be zero to 10 square root or zero to 100 percent uniform for differential flow, depending on whether or not a square-root extractor is used. For all other miniature recorders, charts shall be zero to 100 percent uniform or as called for by the project specifications.

5.3.1. Case Temperature Recorders

Large-case temperature recorders shall be microprocessor based, incorporating linearization of the input signal. Accordingly, charts shall be linear.

5.3.2. Combination Charts

Combination charts shall be used where more than one variable is to be recorded. Multipoint temperature recorders shall have 150 mm (6 in) or wider strip charts. A minimum scale width of 100 mm (4 in) shall be used on all other charts. A minimum six-month supply of charts and ink shall be provided for each recording instrument.

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5.3.3. Instrument Ranges

Charts and scales for locally mounted instruments shall have ranges in accordance with the units shown in Table 1. Charts and scales for other instruments shall have factors to convert to these units.

Table 1: Ranges For Locally Mounted Instruments

Measured Variable or Transmission Signals	**API Preferred SI***	**Customary Units**
Electronic signals	4 to 20 mA	4 to 20 mA
Air signals	20 to 100 kPa gauge, 0.2 to 1.0 bar gauge	3 to 15 psig
Volumes	m^3	scf, bbl, US gal
Flow capacities	m^3/day, m^3/h	US gpm, scfh, scfd, bbl/d, lb/h, bpd, ton/h (steam flow)
Pressures	kPa gauge, kPa abs, mm Hg, bar gauge, bar abs, millibar	psi, psia, in water, in Hg.
Temperatures	°C	°F
Analyzers	As noted (pH, $\%0_2$)	As noted (pH, $\%0_2$)
Level	mm, m, %	in, ft, %

*Units shall be subject to regional or local preference.

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Level Measurement and Control

EPT 05-T-04

October 1992 Draft

Version 0

Table of Contents

Table of Contents **2**

Table of Figures **4**

1. Scope **5**

2. References **5**

2.1. MEPS–Mobil Engineering Practices 5

2.2. Mobil Tutorials 5

2.3. ISA–Instrument Society of America 5

2.4. CHILTON–Chilton 5

3. Principles of Operation **6**

3.1. Floats 6

3.2. Displacers 6

3.3. Differential Pressure Sensors 6

3.4. Contact Probes 6

3.5. Non-Contact Sensors 7

3.6. Level Gauges 7

4. Device Selection **8**

4.1. Floats 8

4.2. Displacers 10

4.3. Differential Pressure 12

4.4. Contact Probes 14

4.5. Non-Contact Sensors 16

4.6. Level Gauges 16

4.7. Switches 23

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4.8. Transmitters 24
4.9. Controllers 26
5. Device Mounting 27
5.1. Internal 27
5.2. External 27
5.3. Bridles 29
5.4. Interface 29
5.5. Level Gauges 30

Table of Figures

Figure 1: Typical Float Sensors 9

Figure 2: Typical Displacer Sensor (Courtesy Controls International, Inc.) 11

Figure 3: Differential Pressure Type Level Measurement 14

Figure 4: Capacitance-Type Level Sensor 15

Figure 5: Pad-Type Gauges (Copyright Material Reprinted Courtesy of Penberthy, Inc.) 17

Figure 6: Tubular Gauge (Copyright Material Reprinted Courtesy of Penberthy, Inc.) 18

Figure 7: Tubular Gauge/Valve with Wire Glass Cage (Copyright Material Reprinted Courtesy of Penberthy, Inc.) 19

Figure 8: Transparent Gauge Glasses (Copyright Material Reprinted Courtesy of Penberthy, Inc.) 20

Figure 9: Cross Section–Transparent Gauge (Copyright Material Reprinted Courtesy of Penberthy, Inc.) 20

Figure 10: Transparent Gauge with Two Sections and Offset Gauge Valves (Copyright Material Reprinted Courtesy of Penberthy, Inc.) 21

Figure 11: Reflex Gauge Glass (Copyright Material Courtesy of Penberthy, Inc.) 22

Figure 12: Cross Section–Reflex Gauge (Copyright Material Reprinted Courtesy of Penberthy, Inc.) 22

Figure 13: Dry Contact Switch (Courtesy of Magnetrol International, Inc., Downers Grove, IL) 24

Figure 14: Typical Level Transmitter (Courtesy of Fisher Controls International, Inc.) 25

Figure 15: External Tank Connections (Courtesy of Magnetrol International, Inc., Downers Grove, IL) 28

1. Scope

This tutorial covers equipment types, selection criteria, operating principles, and typical mounting practices for Level Instruments that are frequently used in oil and gas production and processing facilities. Common types are emphasized; other types are briefly mentioned and references are provided.

2. References

The following Mobil guides and industry publications shall be considered a part of this EPT. Refer to the latest editions unless otherwise specified herein.

2.1. MEPS–Mobil Engineering Practices

MP 32-P-01	General Requirements for Instrumentation
MP 32-P-02	Process Measurement Instrumentation

2.2. Mobil Tutorials

EPT 05-T-02	Controllers and Control Theory
EPT 05-T-10	Programmable Logic Controllers (PLC)

2.3. ISA–Instrument Society of America

ISA S51.1	Process Instrumentation Terminology R(1993)
ISA 520	Specification forms for Process Measurement and Control Instruments, Primary Elements and Control Valves

2.4. CHILTON–Chilton

CHILTON	Instruments Engineer's Handbook (2 Volumes): Process Measurement and Process Control

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3. Principles of Operation

Of the more than 12 types of level sensing elements available, five common basic types are used in hydrocarbon facilities: float sensors, displacer sensors, differential pressure sensors, contact probes, and non-contact sensors. Other sensors, such as bubblers, diaphragm detectors, resistance tapes, and thermal sensors, are discussed in Section 3 of the Chilton Process Measurement Handbook.

3.1. Floats

A float is a device that follows a liquid level or the interface between two liquids of different specific gravities. Standard floats are normally spherical in construction. The float is linked to the operated device (switch or transmitter) via a rod or chain mechanism designed to activate the operated device in proportion of the buoyancy force exerted on the float. See Section 3.9 of the Chilton Process Measurement Handbook for more detailed information.

3.2. Displacers

Displacer-type sensors are similar to floats except that they operate on the basis of a fixed cross-sectional area immersed in a liquid. Typically, a displacer (which is heavier than the liquid) is connected to the operated device (switch or transmitter) via a torque link or spring-loaded lever. As the liquid covers more of the displacer, the displacer's weight decreases and causes a proportional change at the operated device. More specific details are presented in Section 3.8 of the Chilton Process Measurement Handbook.

3.3. Differential Pressure Sensors

As the name implies, a differential pressure level sensor is simply a differential pressure transmitter with one side connected to the vessel in the liquid section and the other side connected to the vapor section. For atmospheric vessels, the high pressure side is connected to the vessel liquid section, and the low pressure side is vented to atmosphere. For pressure vessels, the connections are reversed, and the high pressure side is connected to the vessel's vapor section. See Section 3.7 of the Chilton Process Measurement Handbook for more details. Also, refer to Figure 3 of this document.

3.4. Contact Probes

Contact probes include sensors such as capacitance probes, impedance probes, and infrared probes.

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3.4.1. Capacitance Probes

Capacitance probes are formed of two electrodes; typically, one electrode is the probe and the other is the vessel. When a potential is applied and this probe is immersed in a liquid, the capacitance changes as the level changes, and this produces a proportional change in the activated device, which is normally calibrated in level units. See Section 3.4 of the Chilton Process Measurement Handbook.

3.4.2. Impedance Probes

An impedance probe is basically a modification of a capacitance probe. Generally, the modification is the addition of a second electrode, which provides a back-emf or voltage to overcome the effect of corrosive build-up on a capacitance probe. See Section 3.10 of the Chilton Process Measurement Handbook for more details. Also refer to Section 4.4.2 of this document.

3.4.3. Infrared Probes

Infrared probes (optical detectors) use a light beam to detect level. When a liquid reaches the detector, it disrupts the light beam and activates a sensing unit. These units are used for switch applications only. Infrared detectors are discussed in Section 3.13 and 10.9 of the Chilton Process Measurement Handbook.

3.5. Non-Contact Sensors

Non-contact sensors include ultrasonic and radar systems.

3.5.1. Ultrasonic

Ultrasonic level sensors use sonar principles to detect level. A detailed discussion is presented in Section 3.20 of the Chilton Process Measurement Handbook.

3.5.2. Radar

As the name implies, radar level sensors use electromagnetic waves to detect level. Unlike sonar, a radar beam is not affected by changes in temperature, foam, vapors, or turbulence.

3.6. Level Gauges

Visual observation is the simplest form of level monitoring. There are two basic types of level gauges: gauge glasses and level indicators.

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3.6.1. Gauge Glasses

Level gauge glasses provide a reliable indication of vessel level via a direct view of the contained liquid. See Section 3.11 of the Chilton Process Management Handbook for a detailed discussion.

3.6.2. Level Indicators

The magnetic follower level indicator is similar in design to a gauge glass, except that it contains a float with a magnet that activates an external indicator mechanism, switch, or transmitter. The basic magnetic follower indicator (gauge) is also discussed in Section 3.11 of the Chilton Process Measurement Handbook.

4. Device Selection

4.1. Floats

4.1.1.

Floats are the most common level sensors in low pressure service and can be used at higher pressures if care is taken to prevent collapse of the float due to pressure differential. They are appropriate when the sensing point can be set by the mounting and no adjustment is required or when adjustment over a small range is adequate. Floats are appropriate for most level switch functions. See Figure 1 for a typical float sensor.

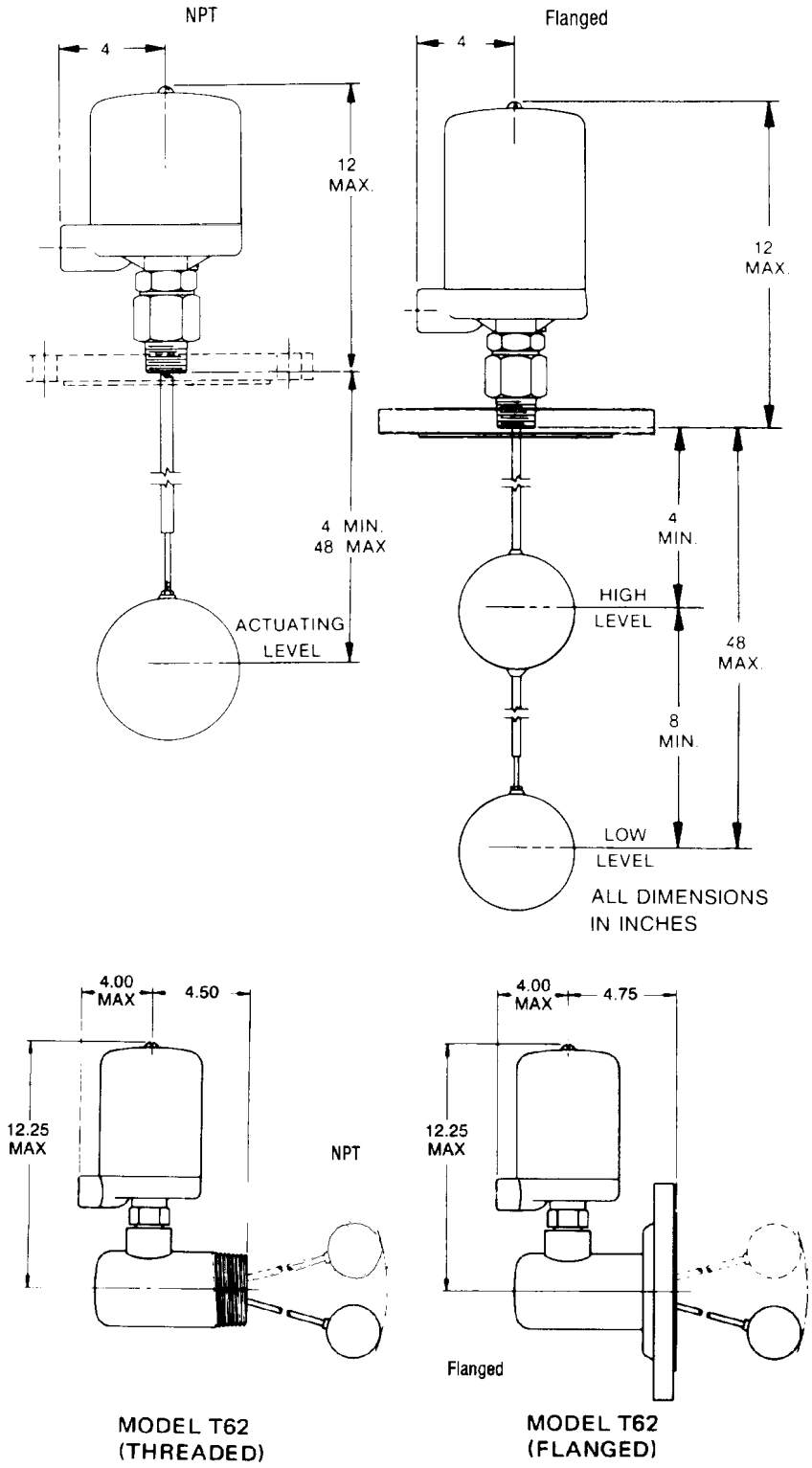

Figure 1: Typical Float Sensors

4.1.2.

The float shall be selected so that it will float in the lower fluid and sink in the upper fluid. The manufacturer's literature will give a minimum specific gravity and a minimum differential specific gravity. The lower fluid shall have a higher specific gravity than the minimum. The difference in specific gravities for an interface shall be at least the manufacturer's stated minimum, and the manufacturer shall be given accurate data to properly ballast the float.

4.1.3.

Wetted float materials shall be suitable for the fluids they contact. For most hydrocarbon use, 316 or 304 stainless steel is suitable. Manufacturers normally publish a chart that can be used to determine which materials are suitable for the particular fluid. If a chart is not available, contact the manufacturer's representative.

4.2. Displacers

4.2.1.

Displacers are somewhat similar to floats except that they are not positively buoyant in either of the fluids of the interface. The level is sensed by measuring the apparent weight of the displacer, usually by spring displacement or torque tube deflection.

4.2.2.

Some displacers are used as switch mechanisms. In a typical "displacer level switch", a displacer of greater specific gravity than the liquid is suspended by a cable attached to a spring. As the liquid level rises over the displacer, its apparent weight decreases, allowing the spring to retract and trigger the switch. To sense more than one level, several displacers can be installed on a cable, and the mechanism can sequentially sense each level set point. This feature of multiple level set points gives displacer level switches the edge over float level switches in wide differential applications, as in pump control.

4.2.3.

When a level is to be measured over a more continuous span, a "displacer level transmitter" (also called a "displacer level controller") may be used. Typically in this type, torque tube deflection is used as a measure of apparent weight, and the displacer itself is a long, slender cylinder. As the liquid level rises and the cylinder becomes incrementally submerged, the torque tube from which it is suspended gradually unwinds. The extent of this unwinding corresponds to a precise liquid level measurement. Displacer level transmitters are available in standard lengths from 4 to 120 inches. Figure 2

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shows a typical version of this type of sensor. Since weight and expense increase with cylinder length, applications requiring more than a 48-inch displacer are normally handled using another type of sensor.

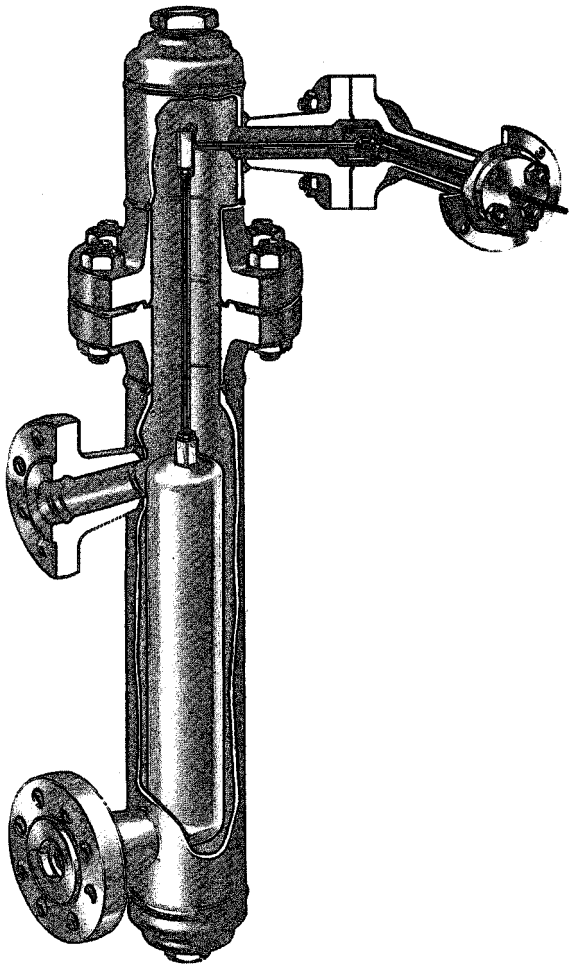

Figure 2: Typical Displacer Sensor (Courtesy Controls International, Inc.)

4.2.4.

Unlike floats, displacers are not hollow, so they are more suitable for high pressure applications. The pressure and temperature ratings for displacers will be given by the manufacturer. The displacer ratings shall meet or exceed the rated pressure and temperature of the vessel. Displacer pressure ratings do not have as large a safety factor as that which is designed into pressure vessels.

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4.2.5.

Wetted displacer materials shall be suitable for the fluids they contact. For most hydrocarbon use, 316 or 304 stainless steel is suitable. Manufacturers normally publish a chart that can be used to determine which standard materials are suitable for a particular fluid. If a chart is not available, contact the manufacturer's representative.

4.3. Differential Pressure

4.3.1.

Differential pressure sensors (DP sensors) are used to measure levels where greater range is needed than can be reasonably obtained with a displacer or float. Typical production facility applications are for fuel, water, or product storage tanks. Differential pressure sensors are best applied in fluids of relatively constant density.

4.3.2.

Differential pressure sensors can be used for sensing liquid interface levels. This requires measuring the differential pressure between a point in the upper fluid and one in the lower fluid. The location of the interface is determined by knowing the specific gravities of the two fluids and the distance between the measuring points. However, since the specific gravity of production fluids tends to vary, use of DP sensors is not practical in most applications.

4.3.3.

DP sensors are useful in fluids that tend to foul displacer or float-type sensors.

4.3.4.

The instruments used for level measurement are very similar to those for flow measurement; however, many manufacturers offer a model for level measurement which mounts directly on a vessel flange. The range is usually specified in inches of water and converts to inches of process fluid by application of a specific gravity correction.

4.3.5.

Instruments mounted remotely are usually connected by tubing and have NPT connections. A method to prevent condensation in the equalizing leg (upper vessel connection) shall be provided if one is used and if the vapors are likely to condense at ambient temperature. Transmitter and controller outputs shall be compatible with the receiving device, and wetted materials shall be selected to avoid excessive corrosion.

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4.3.6.

Level can be derived by measuring the head pressure at the bottom of a vessel or tank. The head at the bottom can be calculated by:

Equation 1

$$H = h\,SG$$

where :

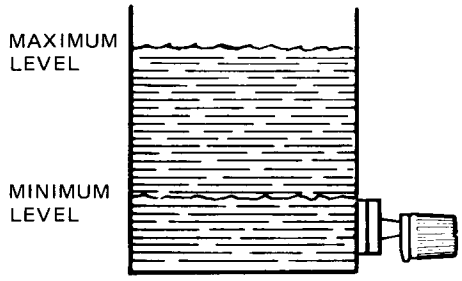
$H = head, in\ H_2O$

$h = height, in$

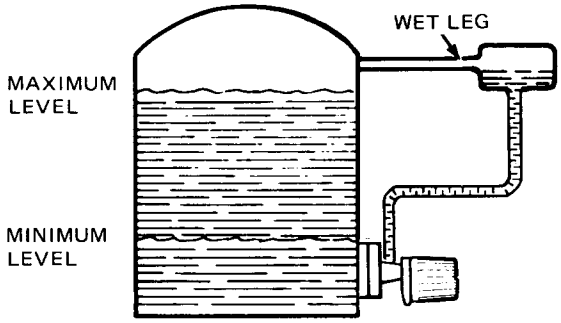
$SG = specific\ gravity\ of\ the\ liquid\ (water = 1)$

4.3.7.

A differential pressure indicator can be provided with a suitable scale, and the height of the liquid can be read directly. As shown in Figure 3, vessels that are vented to atmosphere can use a single connection at the bottom of the tank and measure against atmospheric pressure. In most cases, pressurized vessels must have a liquid sensing point at the bottom and a equalizing vapor sensing point above the highest liquid level.



SUPPRESSED-ZERO APPLICATION



ELEVATED-ZERO APPLICATION

Figure 3: Differential Pressure Type Level Measurement

4.4. Contact Probes

4.4.1. Capacitance Probes

1. Capacitance probes may be used to measure an interface when the difference in dielectric constant between the fluids is significant. Heavy oil/water interfaces and emulsion pads are two of the most common examples. Probes used for switching use horizontal mounting, while those used for continuous measurement use vertical mounting. Capacitance probes are useful to measure the interface between two liquids when the specific gravity difference is too small or the interface is too gradual because of an emulsion pad. Capacitance probes are best applied in fluids where fouling due to paraffin or solids is at a minimum.

2. Figure 4 shows a capacitive level sensing device. The sensing element (rod) is insulated from the tank and acts as one plate of the capacitor; the tank is the other plate. Capacitive level measurements sense the dielectric constant of the material between two plates. The detected capacitance changes are calibrated in units of level.

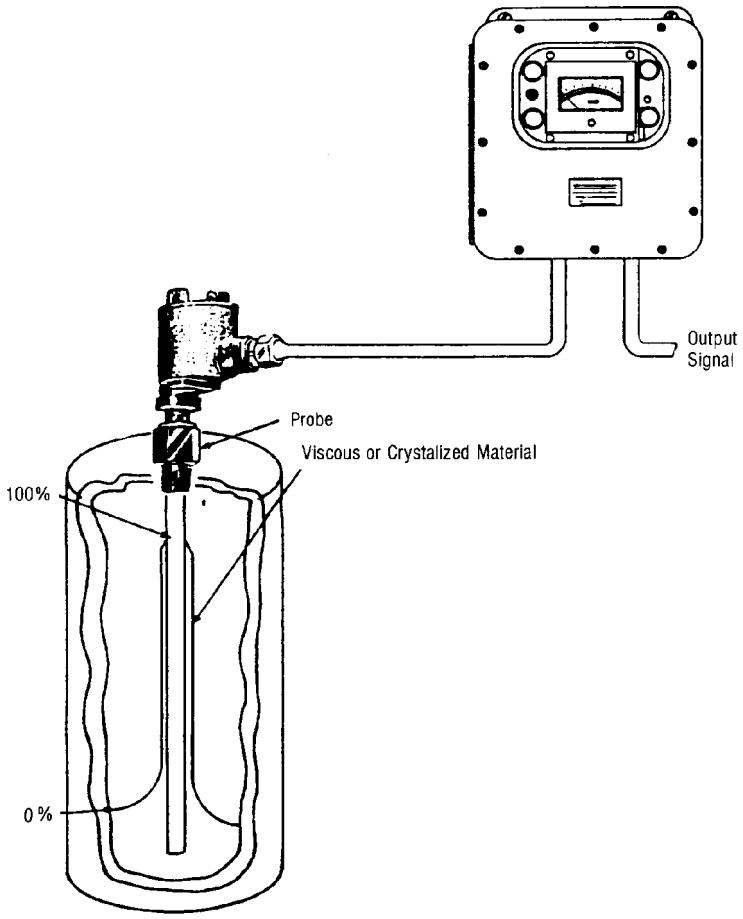


Figure 4: Capacitance-Type Level Sensor

4.4.2. Impedance Probes

Similar to capacitance probes, impedance probes are used in switch and continuous level detection applications. Although slightly more expensive than capacitance probes, impedance probes are less susceptible to corrosive buildup around the probe.

4.4.3. Infrared Probes

Infrared probes, also called optical probes, are not generally used in process applications where the fluid may contain contaminants or emulsions that tend to clog or distort the probe sensor. They are, however, used with good success in storage facilities where the products are reasonably clean. Typical applications are tank high level shutdown systems.

4.5. Non-Contact Sensors

4.5.1. Ultrasonic

Ultrasonic level sensors can be used in both on/off and continuous service applications. They are well suited for applications where it is desirable to minimize contact with the process liquid. In some cases, it is possible to sense level without tank or vessel entry. Usually located at the top of a vessel, ultrasonic sensor systems transmit pulses of sound toward the liquid surface. An echo of reflected pulses returns to the sensor, which notes the time elapsed between the sound's departure and return. This measured time is the basis for a liquid level calculation. A common application is storage vessel level control.

4.5.2. Radar

Radar-based level sensors can be used for point, continuous, and interface sensing applications. Radar sensors are not affected by fluid density. A common application is storage vessel level control.

4.6. Level Gauges

4.6.1. Gauge Glasses

Several types of gauge glasses are manufactured, and proper selection requires knowledge of their characteristics.

1. Pad-type level gauges are those which mount onto a metal pad welded over a circular hole or slot so that the liquid inside the vessel can be directly observed. Low cost is an advantage of this type, and pad-type gauges are sometimes found on economy process packages. The need for a flat surface to mount this type gauge and the need to empty the vessel for cleaning limit its usage. Typical pad-type gauges are shown in Figure 5.

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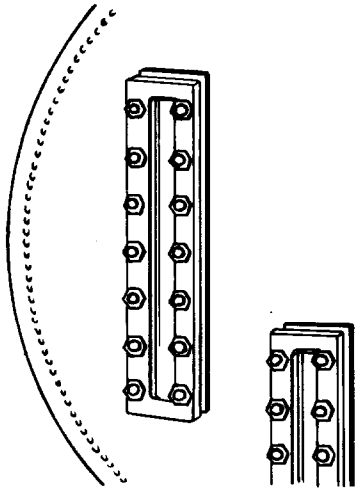

Figure 5: Pad-Type Gauges (Copyright Material Reprinted Courtesy of Penberthy, Inc.)

2. Tubular gauges are those in which a clear glass tube is mounted between two special gauge valves. The process liquid can be observed in the glass tube. Manufacturers of tubular gauges can provide metal rod or wire cage protectors to protect the tube from breakage. Even so, tubular gauges are generally considered unsafe for flammable, toxic or high pressure fluids. Tubular gauges are shown in Figure 6 and 7.

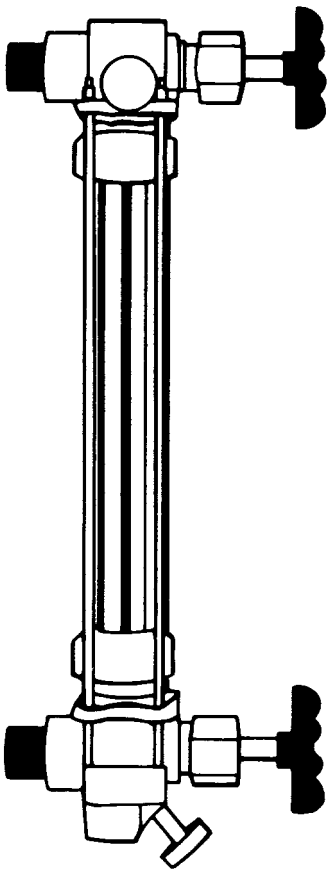

Figure 6: Tubular Gauge (Copyright Material Reprinted Courtesy of Penberthy, Inc.)

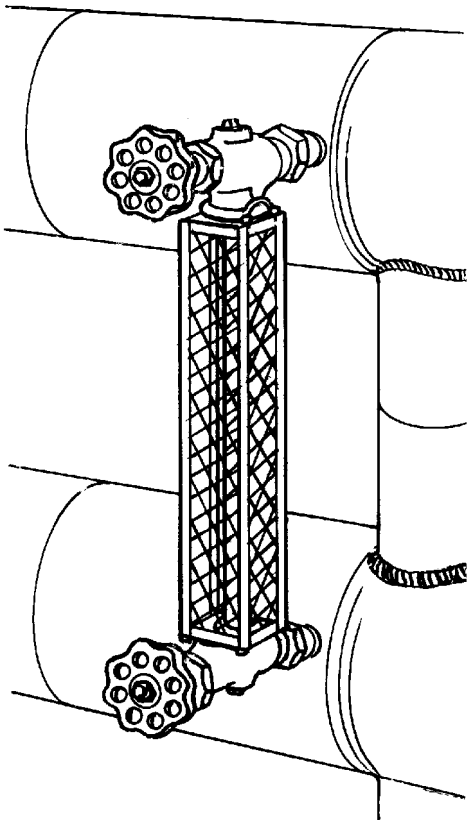

Figure 7: Tubular Gauge/Valve with Wire Glass Cage (Copyright Material Reprinted Courtesy of Penberthy, Inc.)

3. Armored gauge glasses (also know as flat gauge glasses) are used in most production applications. Armored gauges are manufactured in two basic types: transparent and reflex. Both types are available in nominal 14-inch standard lengths with a wide range of materials and pressure ratings (other lengths are available). For large visible lengths, two or more gauges may be assembled together or overlapped. Typically, for safety, gauge overall lengths are limited to 5 feet between connections. Armored gauge glasses are constructed of bolted heavy cast steel or other metal surrounding the glass portion. Small slots allow observation of the fluids without sacrificing the strength and durability of the metal framework.

4. The transparent type has glass on two sides of the chamber so that one looks through the liquid. The liquid can be directly observed, and thus an interface between two liquids of different color can be seen, as well as the interface between a liquid and gas. Where it is difficult to differentiate between the fluids, the gauge is fitted with illuminators. Typically, an illuminator is a light source attached to the apex of a clear plastic wedge that is attached to one side of the gauge. Transparent armored gauge glasses are shown in Figures 8, 9, and 10.

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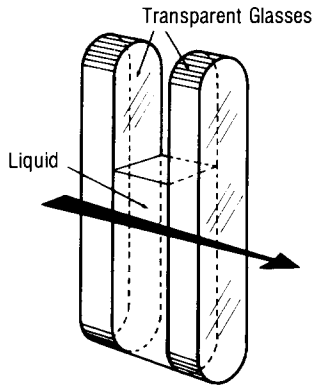

Figure 8: Transparent Gauge Glasses (Copyright Material Reprinted Courtesy of Penberthy, Inc.)

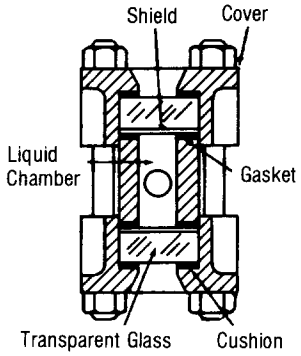

Figure 9: Cross Section–Transparent Gauge (Copyright Material Reprinted Courtesy of Penberthy, Inc.)

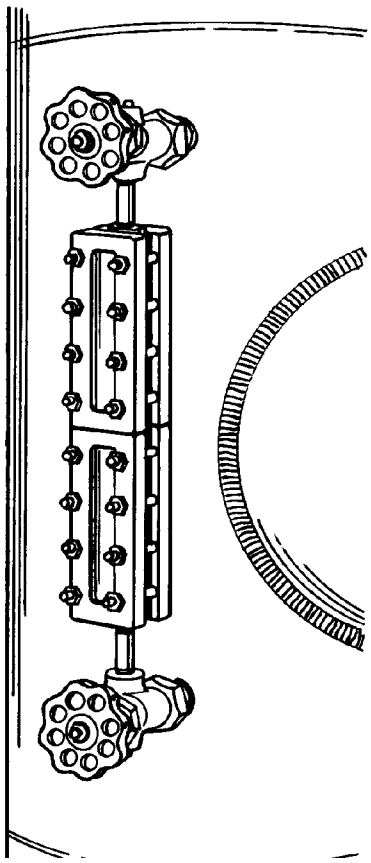

Figure 10: Transparent Gauge with Two Sections and Offset Gauge Valves (Copyright Material Reprinted Courtesy of Penberthy, Inc.)

5. The reflex-type gauge has a single glass with prisms cut in the glass on the chamber side. Light striking the glass in the vapor area is refracted back to the viewer (the vapor space appears silvery white). Light striking the glass in the liquid zone is refracted into the liquid, making it appear dark (black). Liquid level can easily observed, even in low light conditions. While this characteristic is usually beneficial, it prevents use of reflex gauges when liquid interfaces or color must be observed. Reflex gauge glasses are not recommended when viscous or dirty liquids are to be measured, since the liquid may coat the reflex surface, resulting in a false level indication. Figures 11 and 12 illustrate reflex gauges.

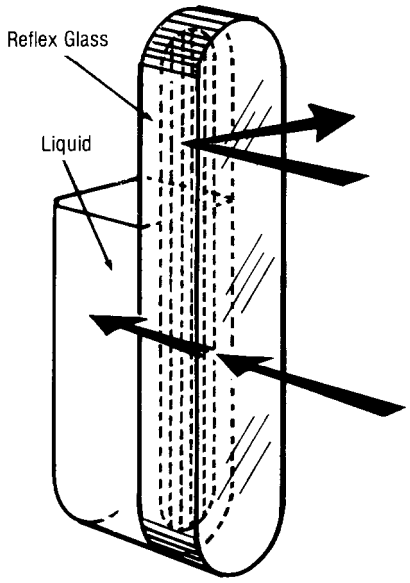

Figure 11: Reflex Gauge Glass (Copyright Material Courtesy of Penberthy, Inc.)

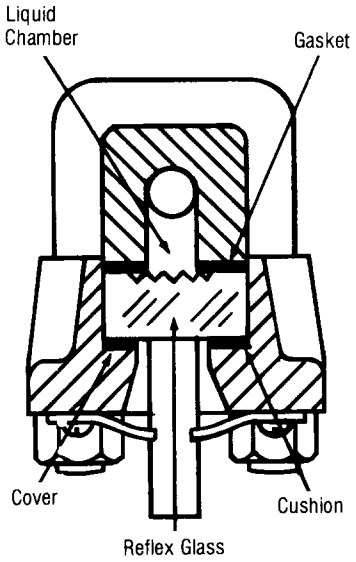

Figure 12: Cross Section–Reflex Gauge (Copyright Material Reprinted Courtesy of Penberthy, Inc.)

6. Several accessories for level gauges are available. The most common are frost extensions, illuminators, and external heating coils. Frost extensions are used in low temperature service to prevent frost from forming on the glass viewing slot. Different extension lengths are available and are a function of the process temperature. In any case, the extensions shall extend past the insulation.

7. Illuminators provide backlighting for transparent level gauges through the use of a single source light and lucite reflector. In most applications, the illuminators shall be explosion-proof.

8. Level gauges can be equipped with external tubes for heating. Heating coils are used to prevent fluid freeze-up in the level gauge.

9. Level gauge glasses are manufactured to different pressure and temperature ratings. The pressure and temperature rating of the selected instrument shall equal or exceed the rated pressure and temperature of the vessel. Level gauge costs range from approximately $20/ft (U.S.) for tubular to $200/ft for armored.

4.6.2. Level Indicators

Magnetic follower level indicators are used in toxic or corrosive services. Most designs consist of a stainless steel gauge with an internal float riding on the liquid. A magnet in the float is coupled to the external indicator or device. An advantage of these units is the availability of both switches and transmitters designed for attachment directly to the indicator column. Although the cost of a magnetic follower level indicator is much more than a standard level gauge (on the order of 2 to 3 times), they become economic when applying integral level switches and transmitters. The economics include the reduction not only in gauge mounting costs but the separate mounting costs of switches and/or transmitters.

4.7. Switches

Switches are available in the "normally open" or "normally closed" position; these designations refer to the switch position when there is no electrical power or pneumatic signal. Switches merely turn either an electronic or pneumatic signal on or off as required for the control scheme. Any of the level sensors discussed in Section 3 can be used to activate the switch.

4.7.1. Electric

The most widely used and approved switch is the dry contact type. An example of this switch is illustrated in Figure 13.

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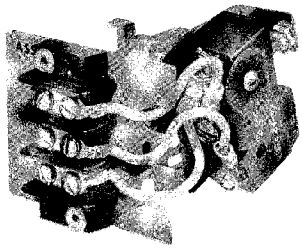

Figure 13: Dry Contact Switch (Courtesy of Magnetrol International, Inc., Downers Grove, IL)

1. The electrical switch is usually either single-pole, double-throw (SPDT) or double-pole, double-throw (DPDT). DPDT switches are preferred to allow flexibility in control circuits.

2. The cost of electric level switches can vary from $150 to $800 U.S. depending on specified features (e.g., gold plated contacts, stainless steel, body, etc.) The average price of level switches used in the petroleum industry is approximately $400 U.S.

4.7.2. Pneumatic

1. Pneumatic level switches are generally the same as electric switches but have a two- or three-way valve (instead of a contact block) as the controlled element. These switches have the same basic features as an electric switch. They are commonly used on small facilities where local control of individual skid units is employed. Costs of these switches are generally less than that for the electric type; the average is approximately $300 U.S.

2. A detailed discussion of various switch types and operations is presented in Chapter 3 of the Chilton Process Measurement Handbook.

4.8. Transmitters

4.8.1.

Level transmitters are used to interface control, indication, and data systems with the process. They are also used when several devices are to be operated from a single measurement. The output is usually 4-20 milliamps for electronic transmitters or 20 to 100 kPa (3-15 psig) for pneumatic transmitters. Other signals can be used if required by the receiver, but these are the most common and shall be used if possible. A typical electronic level transmitter is shown in Figure 14.

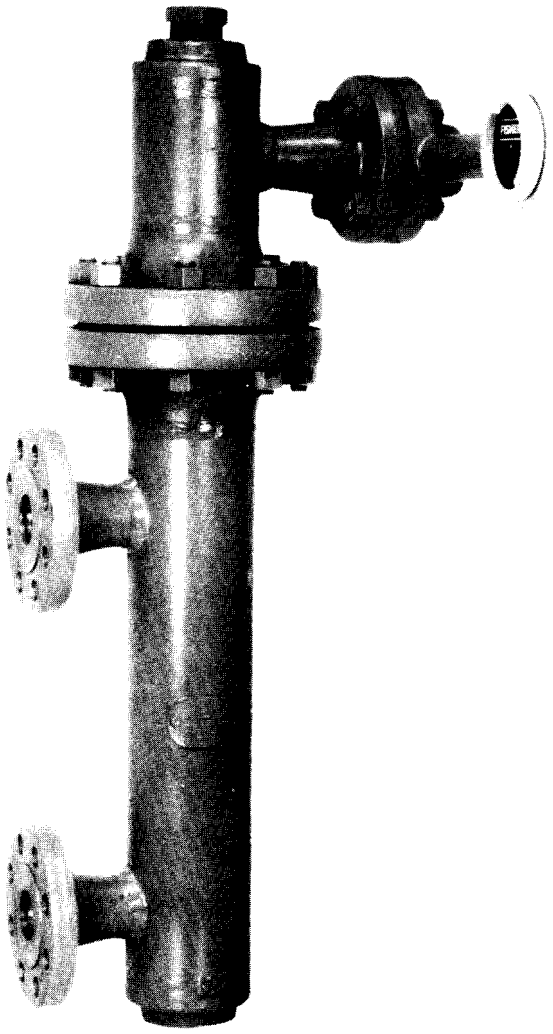

Figure 14: Typical Level Transmitter (Courtesy of Fisher Controls International, Inc.)

4.8.2.

Several companies offer microprocessor-based level transmitters, sometimes called "smart transmitters". These transmitters can be remotely programmed and/or calibrated for any desired range, either by the main process computer or by a special programmer. These transmitters are usually used in Distributed Control System (DCS) applications (see EPT 05-T-10).

4.8.3.

A detailed discussion of transmitters is presented in Section 3 of the Chilton Process Measurement Handbook, and specific calculation procedures for DP

cell level transmitter selection is presented in Section 3.7 of the Chilton Process Measurement Handbook.

4.9. Controllers

4.9.1.

Every process vessel shall have some form of level control. In some vessels the liquid overflows a weir and neither operator control nor automatic control is required. However, this is possible only for atmospheric vessels or where vessels designed to operate at the same pressure are connected in series. If the liquid flows from a vessel to another which is to operate at lower pressure, a level control valve shall be needed to assure that the first vessel is not emptied of liquid; if this emptying occurs, gas entering the first vessel could "blowby" to the second vessel, putting both vessels in pressure communication. Some form of control is necessary for this level control valve.

4.9.2.

Manual control is practical for some situations where the flow is low and fairly constant. Visual observation of the level and adjustment of a valve or other device may be all that is required. Except for very low liquid flow applications where infrequent emptying of the vessel is all that is required, manual control is often difficult in production operations due to the fluctuating nature of the liquid flow and the potential hazards of gas blowby and overpressure.

4.9.3.

Automatic control by instruments is usually required for most separator and other production applications. A level controller receives input from any of the sensors described in Section 3, "Principles of Operation", or from a transmitter. It converts this input either to a pneumatic signal or electronic signal which is used to activate a control valve as required to maintain a near constant level in the vessel or tank. The controller output is usually either a 20 to 100 or 40 to 200 kPa (3 to 15 or 6 to 30 psig) pneumatic signal. Electronic controller output is 4 to 20 mA.

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5. Device Mounting

5.1. Internal

5.1.1.

Level instruments can be mounted so that the float or displacer is installed inside the vessel. This method is simple and inexpensive. Vessels that can be removed from service and drained for level instrument maintenance without serious interruption of the facility often use internal mounting. Internal mounting is also used when the fluid is too viscous for flow through small pipes at ambient temperature. In some locations, internal mounting is preferred where there are ambient conditions of short duration sufficient to require heat tracing of externally mounted level devices.

5.1.2.

The main problem with internal mounting is that the instrument cannot be serviced without interruption of the process. Another problem is that vessels with considerable flow have currents and turbulence in their fluids. This fluid movement can cause external force, swinging, and binding of the sensor.

5.1.3.

Fluid movement problems can be greatly reduced by using a stilling well. A stilling well is a pipe that is fixed to the vessel and surrounds the level sensor. Enough clearance is provided to allow free movement of the sensor. Numerous slots or holes are provided in the well to ensure that the level inside the well is the same as in the surrounding vessel.

5.1.4.

The vessel nozzle shall be large enough to allow insertion of the sensor. The internals of the vessel shall be designed so that the insertion and operation of the sensor is not hampered.

5.2. External

5.2.1.

Level sensors can be mounted in a small vessel called an external cage, as shown in Figure 15. The cage is connected to the main vessel through

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nozzles and valves at the top and bottom of the cage. The liquid moves through the nozzles to maintain the same level in the cage as in the vessel. The cost of external mounting is more than internal mounting because of the added cage, valves, and additional nozzle.

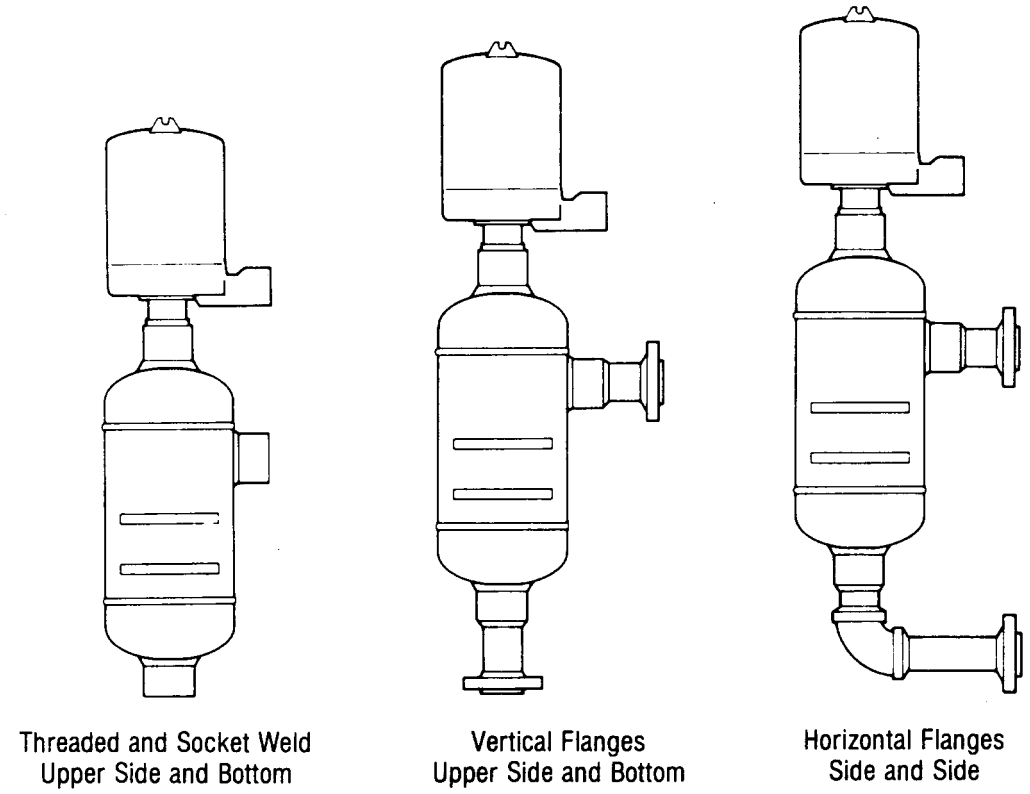

Figure 15: External Tank Connections (Courtesy of Magnetrol International, Inc., Downers Grove, IL)

5.2.2.

External mounting is very common for level switches that have to be tested periodically. The switch can be tested without affecting the actual level in the vessel. A low level switch can be tested by isolating it from the vessel and carefully opening both the vent valve and the drain valve. A high level switch can be tested by closing the top connection to the vessel and opening the vent valve, provided the vessel is operating at a sufficiently high pressure to cause the level in the cage to rise past the switch when the liquid in the cage is vented to the atmosphere.

5.2.3.

The advantage of eternal mounting is that the instrument can be isolated from the vessel and serviced or replaced without removing the vessel from service.

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External mounting is quite common to reduce expensive interruptions of product flow for level instrument maintenance.

5.2.4.

Viscous liquids, high paraffin liquids, or liquids with significant solids content can cause slow flow or clog the valves or cage. This can cause the level in the cage to lag the level in the vessel or make the sensor inoperative in severe cases. High pour point liquids may solidify in the cage unless the cage is insulated and/or heat traced.

5.3. Bridles

5.3.1.

A bridle is a vertical standpipe that is mounted on the vessel at the sides near the top and bottom. The standpipe is usually 51 to 102 mm (2 to 4 in) in diameter and is connected to the vessel through isolation valves. The lower vessel connection shall be installed in a horizontal position to reduce plugging. Several level instruments are attached to the standpipe at the appropriate levels. Bridle mounting is a form of external mounting that shares the same advantages and disadvantages. Bridles have the added advantages of reducing the number of penetrations in the vessel and the fact that an instrument can be moved by modifying the standpipe without cutting and welding on a coded vessel. In addition, if external mounting is required, bridles tend to be more economical than individual external instruments. The use of bridles that are typically further removed from the vessel may aggravate the problems associated with viscous fluids.

5.3.2.

Instruments installed on a bridle often have individual isolation and drain valves. The bridle usually has vent and drain valves so that the level in the bridle can be varied independently of the vessel level for testing and for service.

5.4. Interface

Level instruments used to measure the interface between two liquids in a three-phase vessel shall have the top connection connected into the upper liquid phase if they are mounted externally. An instrument connected into the lower liquid phase and the gas phase will not show a true level. It is necessary to provide three connections for bridles used for interface levels so that all three phases have a path into the standpipe and the levels can equalize with those in the vessel.

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5.5. Level Gauges

5.5.1.

Level gauge accuracy can be reduced significantly by high viscosity liquids that flow slowly or boiling liquids that are turbulent with no flow. A solution to both of these problems is to use a gauge with a larger than normal liquid chamber. Large chamber gauges are available in tubular, transparent, and reflex types.

5.5.2.

Level gauges are usually mounted with angle valves called gauge cocks. These valves are available in several materials, forged carbon steel and stainless steel being the most common. Carbon steel is usually used for hydrocarbon service. Stainless steel gauge cocks shall be used for more corrosive applications. Gauge cocks come in straight and offset patterns. The offset pattern is usually specified because it allows the gauge to be cleaned without disassembly. Gauge cocks are normally equipped with ball velocity checks to minimize leakage to the atmosphere if the level gauge leaks or breaks.

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Temperature Measurement and Control

EPT 05-T-05

November 1992 Draft

Version 0

Table of Contents

1. Scope 6

2. References 6

2.1. MEPS–Mobil Engineering Practices 6

2.2. Mobil Tutorials 6

2.3. CHILTON–Chilton 6

2.4. ISA–Instrument Society of America 6

2.5. MISC–Miscellaneous 6

3. Principles of Operation 7

3.1. General 7

3.2. Filled Systems 7

3.3. Bimetallic Elements 9

3.4. RTD 10

3.5. Thermocouples 12

3.6. Pyrometers 13

4. Device Selection 13

4.1. Thermowells 13

4.2. Bimetallic Thermometers 25

4.3. Glass Tube Thermometers 27

4.4. Digital Thermometers 29

4.5. Filled-System Thermometers 30

4.6. Infrared Pyrometers 31

4.7. Resistance Temperature Detectors 32

4.8. Thermocouples 36

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4.9. Temperature Switches 40
4.10. Temperature Transmitters 46
4.11. Temperature Controllers 48
4.12. Temperature Recorders 48
5. Sensor Testing and Calibration 50
5.1. 50
5.2. 50
5.3. 51

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Table of Figures

Figure 1: Schematics Illustrating Several Types of Filled System Devices and Their SAMA Class Designations (Reproduced Courtesy of Chilton Book Co., from Instrument Engineers Handbook by B.G. Liptak) 9

Figure 2: Schematic Illustrating the Concept of Bimetallic Temperature Elements (Flat and Helical) (after ISA) 10

Figure 3: Resistance Temperature Relationships for Various Thermoresistive Materials at Elevated Temperatures (Reproduced Courtesy of McGraw-Hill, from Process Instruments and Controls Handbook by Douglas M. Considine) 12

Figure 4: Schematic Depicting a Hardware Compensated Thermocouple Assembly13

Figure 5: Typical Thermowells 14

Figure 6: Schematics of Threaded Thermowells for Screwed-On Connection (After McFadden and Assoc.) 17

Figure 7: Schematics of Flanged Thermowells and a Socket-Welded Thermowell ...18

Figure 8: Schematics of Screwed Thermowell Installation Alternatives 21

Figure 9: Schematics of Flanged Thermowell Installation Alternatives 22

Figure 10: Various Types of Bimetallic Thermometers (Reproduced Courtesy of Weksler Instruments) 26

Figure 11: Several Types of Glass Tube Thermometers (Reproduced Courtesy of Weksler Instruments) 28

Figure 12: Digital Thermometer for Field Mounting (Reproduced Courtesy of Ametek).....30

Figure 13: Filled-System Thermometers (Reproduced Courtesy of Ashcroft, Dresser Industries) 31

Figure 14: Infrared Pyrometer Used to Sense Temperature at a Distance (Reproduced Courtesy of Omega Engineering, Inc., an Omega Technologies Co. Copyright 1988 All Rights Reserved) 32

Figure 15: Various Methods for Attaching an RTD or Thermocouple Sheath to a Thermowell Fitting (Reproduced Courtesy of Rosemount Inc.) 34

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Figure 16: A Nipple-Union-Nipple Extension Assembly for Installing an RTD or Thermocouple Element into a Thermowell (Reproduced Courtesy of Omega Engineering Inc. and Omega Technologies Co. Copyright 1988, All Rights Reserved.) 35

Figure 17: Three Basic Types of Thermocouple Assemblies (Reproduced Courtesy of Omega Engineering Inc. an Omega Technologies Co. Copyright 1988, All Rights Reserved.)....37

Figure 18: Output Versus Temperature Curves for the Four Types of Base Metal Thermocouples (Types J, K, T, and E) 39

Figure 19: A Mechanically Operated Vapor-Filled System Electric Temperature Switch (Reproduced Courtesy of Custom Control Sensors, Inc.) 41

Figure 20: Typical Solid-State Electric Temperature Switch (Reproduced Courtesy of Rochester Instrument Systems) 43

Figure 21: Temperature Switch Housings for Various Installations (Reproduced Courtesy of SOR, Inc.) 45

Figure 22: Typical Pneumatic Temperature Valve (Switch) (Reproduced Courtesy of AMOT Controls Corp.) 46

Figure 23: Typical Temperature Transmitter Designed for Field Mounting (Reproduced Courtesy of Rosemount Inc.) 47

Figure 24: A Filled System Temperature Recorder with Clock Driven Circular Charts: Internal View of a Three Pen Recorder with Spring Drive Mechanism (Reproduced Courtesy of Weksler Instrument Corp.) 49

Figure 25: A Multipoint Remote Temperature Recorder (Reproduced Courtesy of Honeywell Inc.)....50

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1. Scope

This tutorial discusses the types of temperature instruments that are frequently used in oil and gas production/processing facilities. Many other types of temperature measurement instruments are available and are either covered briefly or referenced.

2. References

The following Mobil tutorial and industry publications shall be considered a part of this EPT. Refer to the latest editions unless otherwise specified herein.

2.1. MEPS–Mobil Engineering Practices

MP 32-P-02	Process Measurement Instrumentation

2.2. Mobil Tutorials

EPT 05-T-02	Controllers and Control Theory

2.3. CHILTON–Chilton

CHILTON	Instruments Engineer's Handbook (2 Volumes): Process Measurement and Process Control

2.4. ISA–Instrument Society of America

ISA S51.1	Process Instrumentation Terminology R(1993)
ISA 520	Specification Forms for Process Measurement and Control Instruments, Primary Elements and Control Valves

2.5. MISC–Miscellaneous

MISC-55	SAMA - Scientific Apparatus Makers Association (for Filled Systems)

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3. Principles of Operation

3.1. General

3.1.1.

Temperature measurement is used in virtually all oil and gas production facilities. Even the simplest facilities include thermometers to monitor the temperatures of wellstreams and separators.

3.1.2.

Many emulsions require heat to achieve the required separation of oil and water. Gas Dehydration systems require heat to regenerate the desiccant. Gas streams are heated to prevent hydrate formation. Each of these examples requires accurate temperature control to ensure that adequate heat is added without wasting energy. Cooling of streams after processing or gas compression also requires temperature control to achieve the desired condition and conserve energy.

3.1.3.

The amount of heat in a body cannot be directly measured, but the temperature of the body can be measured and then the amount of heat calculated from the mass. As heat is applied to a mass/process several changes that can be observed and used to measure the temperature of the mass or process occur. Changes of primary interest are change of state (liquid to vapor, etc.), expansion and contraction, and changes in electrical characteristics. Sensors that are based on these characteristics include filled system elements, bimetallic elements, RTDs, thermocouples, and pyrometers.

3.2. Filled Systems

3.2.1.

A filled system is one in which a fixed mass of fluid is sealed in a volume that varies relatively little with temperature. The pressure variations with temperature within the system are sensed to measure the temperature. The fluid can be one that remains gaseous, stays liquid, or changes state over the temperature range of interest. Each of these fluid choices has some advantages and disadvantages.

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3.2.2.

The Scientific Apparatus Makers Association (SAMA) has published a standard that assigns a classification to different types of filled systems. The use of SAMA classifications has diminished as electronic temperature sensing has become dominant and manufacturers have reduced the available options in their filled systems.

3.2.3.

The simplest form of filled system is the ordinary alcohol or mercury thermometer. In this type of system, a bulb is attached to a glass capillary tube. As the temperature rises, the liquid expands into the capillary tube and rises to indicate the temperature. A scale is either painted onto the glass tube or fastened behind it for calibration.

3.2.4.

Filled systems can also consist of a bulb, a capillary tube, and a pressure sensor. The fluid within the bulb, when subjected to a temperature change, will change state and via the capillary cause a corresponding change in the pressure sensor. This change in pressure is converted to temperature indication or control by the readout instrument (indicator, controller, etc). Illustrations of typical filled systems are shown in Figure 1. A detailed description of filled systems is presented in Section 4.4 of the Chilton Process Measurement Handbook.

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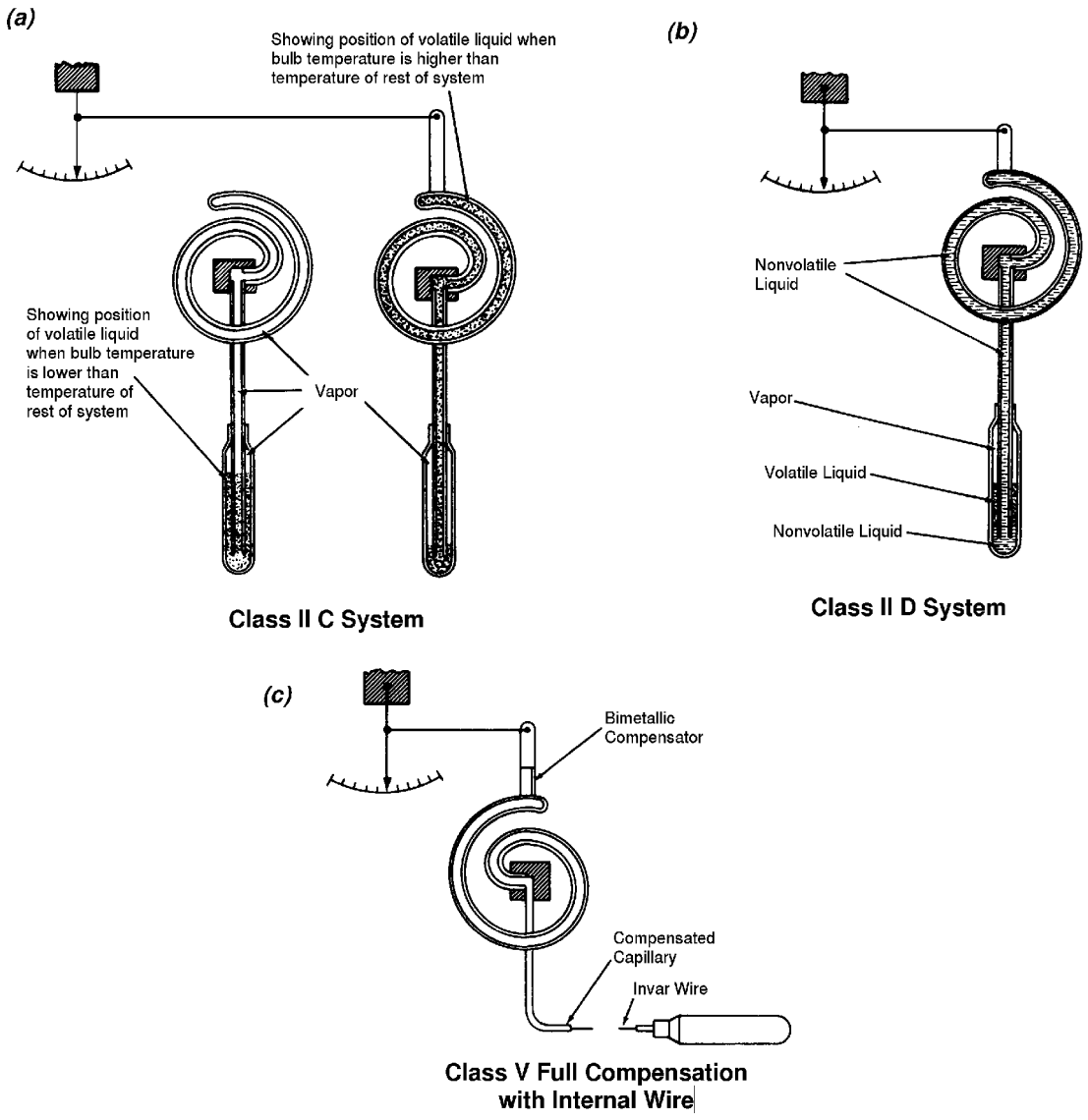
(a)
Showing position of volatile liquid when bulb temperature is higher than temperature of rest of system
Showing position of volatile liquid when bulb temperature is lower than temperature of rest of system
Vapor
Class II C System
(b)
Nonvolatile Liquid
Vapor
Volatile Liquid
Nonvolatile Liquid
Class II D System
(c)
Bimetallic Compensator
Compensated Capillary
Invar Wire
Class V Full Compensation with Internal Wire

Figure 1: Schematics Illustrating Several Types of Filled System Devices and Their SAMA Class Designations (Reproduced Courtesy of Chilton Book Co., from Instrument Engineers Handbook by B.G. Liptak)

3.3. Bimetallic Elements

3.3.1.

Most substances expand when the temperature increases and contract when the temperature decreases, but different substances expand and contract at

different rates. If two metals with different coefficients of thermal expansion are bonded together as shown in the left drawing of Figure 2, an increase in temperature will cause the free end to bend toward the material with the lower coefficient of thermal expansion. This bending motion can be observed visually or used to close a contact.

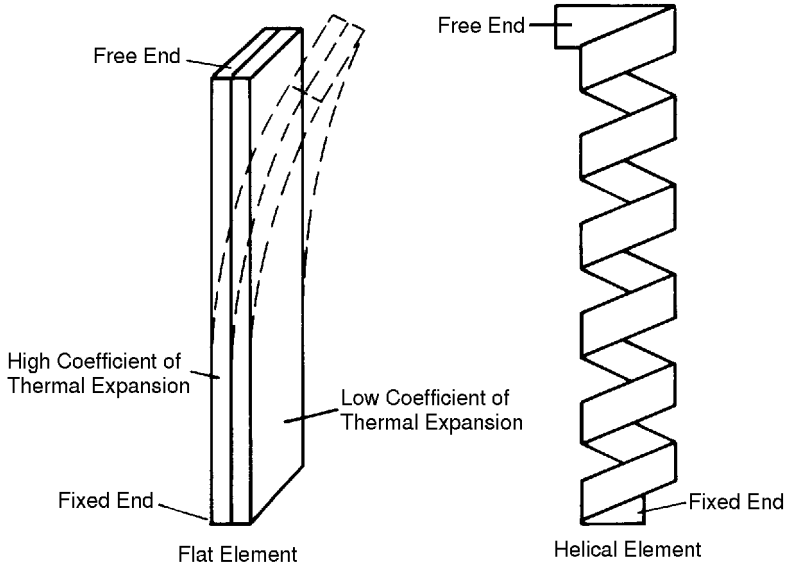

Figure 2: Schematic Illustrating the Concept of Bimetallic Temperature Elements (Flat and Helical) (after ISA)

3.3.2.

A bimetallic element can be formed in a spiral or helix to increase the amount of motion available for a given temperature change. Figure 2 shows both the helix and the flat forms.

3.3.3.

Bimetallic elements are primarily used in thermometers, indicators, and switches. A detailed description of bimetallic thermometers and switches is presented in Sections 4.2 and 4.12 of the Chilton Process Measurement Handbook.

3.4. RTD

3.4.1.

A resistance temperature detector (RTD) is a conductor of known characteristics constructed for insertion into the medium for temperature

measurement. The resistance of a conductor usually increases as the temperature increases; therefore, if the properties of the conductor are known, the temperature can be calculated from the measured resistance.

3.4.2.

When a potential is applied to the RTD, a current will flow in proportion to the circuit resistance. The resistance is then determined by Ohm's Law (E = IR). The standard platinum industrial RTD is the most common type in use. Figure 3 illustrates the resistance-temperature relationship for common metals. Platinum RTDs have a rate of change of 0.385 ohms per °C of temperature change and have a resistance of 100 ohms at 0°C (32°F). The temperature detected by a platinum RTD can be calculated as follows:

$$C = \frac{(ohms\ reading\ -100)}{0.385}$$

3.4.3.

A detailed discussion is provided in Section 4.11 of the Chilton Process Measurement Handbook.

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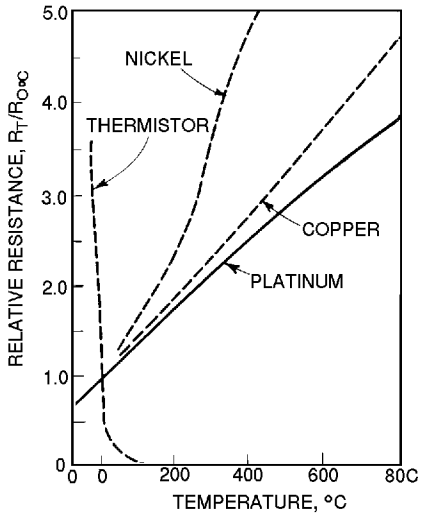

Figure 3: Resistance Temperature Relationships for Various Thermoresistive Materials at Elevated Temperatures (Reproduced Courtesy of McGraw-Hill, from Process Instruments and Controls Handbook by Douglas M. Considine)

3.5. Thermocouples

3.5.1.

A thermocouple consists of two different types of metal (conductors) connected together at a point. This connection point is called the "hot junction" since it is the point subjected to the heat source. When this junction is heated and the conductors are connected to a measuring device, an emf (electromotive force) shall be generated. This force causes a current to flow in the measuring circuit. The current is translated into a temperature measurement of the heat source.

3.5.2.

The configuration of thermocouple sensors is critical, and it varies with application. Figure 4 depicts a standard (hardware compensated) thermocouple assembly.

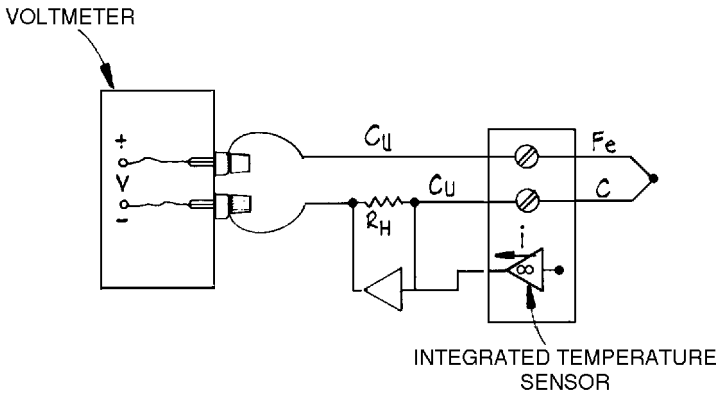

Figure 4: Schematic Depicting a Hardware Compensated Thermocouple Assembly

3.5.3.

Thermocouples are discussed in detail in Section 4.14 of the Chilton Process Measurement Handbook.

3.6. Pyrometers

Radiation-type pyrometers constitute the most common type of pyrometer in use in the petroleum industry. In this type, an optical/infrared meter is used as an optical system that collects the visible and infrared energy and focuses it on a detector that converts this energy to an electrical signal. This electrical signal then operates the readout device. A detailed discussion of pyrometers is presented in Sections 4.8 and 4.9 of the Chilton Process Measurement Handbook. Other types of temperature sensors, although not commonly in use in the petroleum industry, are presented in Chapter 4 of the Chilton Process Measurement Handbook.

4. Device Selection

4.1. Thermowells

4.1.1. General

1. A thermowell is a sheath that protects a thermal sensor from the process fluid. Almost all temperature sensors in production facilities, with the

exceptions of stack temperature and pilot flame sensors, are installed in thermowells. A thermowell is normally a part of the temperature sensing device. Some typical thermowells are shown in Figure 5.

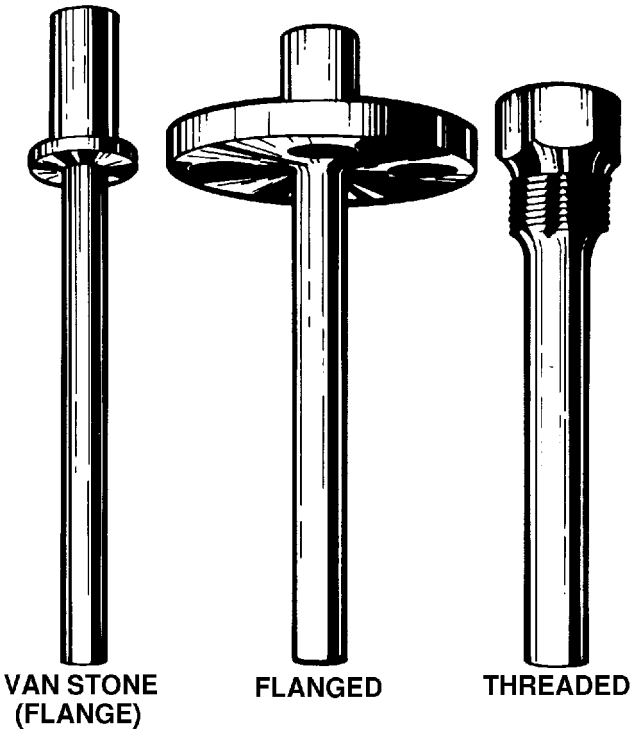

Figure 5: Typical Thermowells

2. The use of thermowells offers two main advantages. First, the process fluid does not contact the temperature sensor, thus the sensor is not subject to corrosion or erosion from the fluid and does not have to withstand the process pressure. Second, the sensor can be removed and replaced without shutting down the process or releasing fluid. Two disadvantages of having thermowells are: decreased heat transfer rate, which increases the delay between process temperature change and measurement; and increased cost. The advantages of using thermowells generally outweigh the disadvantages in production facilities.

3. Since the thermowell is in constant contact with the process fluid, it shall be constructed of a material that will not be subject to excessive corrosion or erosion. A thermowell can be made from any material that can be machined, so custom made wells are available for most fluids. Type 316 stainless steel is suitable for almost all process facility applications and is the most used material. Type 304 stainless steel is also suitable for most applications and is about 25 percent less expensive than type 316. Type 316 has molybdenum added, giving it greater pitting resistance than type 304 as well as better corrosion resistance to common salts and acids. The average cost of a type 316 thermowell is

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less than $50 U.S., which makes the actual money savings by selecting type 304 small.

4. Carbon steel is seldom used in production facilities because of corrosion problems. Even when the process fluid is not corrosive to carbon steel, there may be a problem with external corrosion in the place where the sensor threads into the thermowell. Brass is softer than steel and thus is more susceptible to thread stripping and other mechanical failures, and it is used only in special non-critical applications.

5. A thermowell is a pressure-containing device and is therefore subject to the same sort of failures as piping elements. A thermowell can collapse from external pressure if its wall thickness is insufficient. A minor distortion of the well can bind the element and prevent removal. A major failure can allow process fluid to enter the well and apply process pressure to the sensor connection.

6. The inside dimensions of the thermowell shall be compatible with the sensor. When the sensor and thermowell are purchased as a unit, this compatibility is ensured by the vendor. If the sensor and thermowell are purchased separately, the purchaser shall ensure compatibility. Three factors are involved: the diameter of the bore, the depth of the bore, and the connection.

7. Sensor diameters vary with sensor types. Bimetallic thermometer and electronic sensors usually have 6.35 mm ($^1/_4$ in) or 9.53 mm ($^3/_8$ in) insertion diameters. Glass thermometers are generally 7 mm (0.275 in) and will fit into a 9.53 mm ($^3/_8$ in) well.

8. The diameter of the bore shall be slightly larger than the sensor, with just enough clearance to allow insertion and withdrawal without excessive force. Excessive clearance in the bore decreases the heat transfer efficiency and increases the lag between the process temperature change and the measurement change. The usual clearance is 0.25 mm (0.01 in).

9. The best temperature measurement occurs when the sensor is in contact with the bottom of the well. Some sensors are adjustable or spring-loaded to allow contact, but the well shall be within certain tolerance for depth. A small amount of oil or grease in the thermowell aids heat transfer. This technique is usually reserved for measurements for which response time is critical, since the transfer fluid is messy and can collect dirt and other contaminants. One alternate is to use a metal sheath or shim to fill the void. Sensors are available in a variety of lengths to accommodate various insertion depths.

10. The sensor is usually firmly fastened into the well. The most common method is by a 13 mm ($^1/_2$ in) NPT threaded connection. The sensor usually has the male fitting, and the well has the female thread. Other sizes and types of connections are used when the sensor is too large to use 13 mm ($^1/_2$ in) NPT or when it is not suitable for threading.

11. Thermowell connections to the process may be screwed, flanged, Van-Stone flanged, or socket welded. This connection is subject to full

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process pressure and is usually governed by the same limitations as the other process connections. The connection and the well itself shall have the same or higher pressure and temperature ratings as the process piping and equipment.

12. The most common connection is to machine threads into the thermowell and weld a threaded connection to the piping or vessel. Examples of thermowells for screwed connection are shown in Figure 6. The connection size is usually 19 mm ($^3/_4$ in) NPT, but 25 mm (1 in) NPT has a slightly stronger connection at a slightly higher price. Some manufacturers offer 13 mm ($^1/_2$ in) NPT connections, but these are not usually considered rugged enough for hydrocarbon processing. Screwed connections offer the advantages of low cost and the shortest possible well for the required insertion. Mobil backwelds a screwed thermowell to insure no leakage, particularly for toxic processes.

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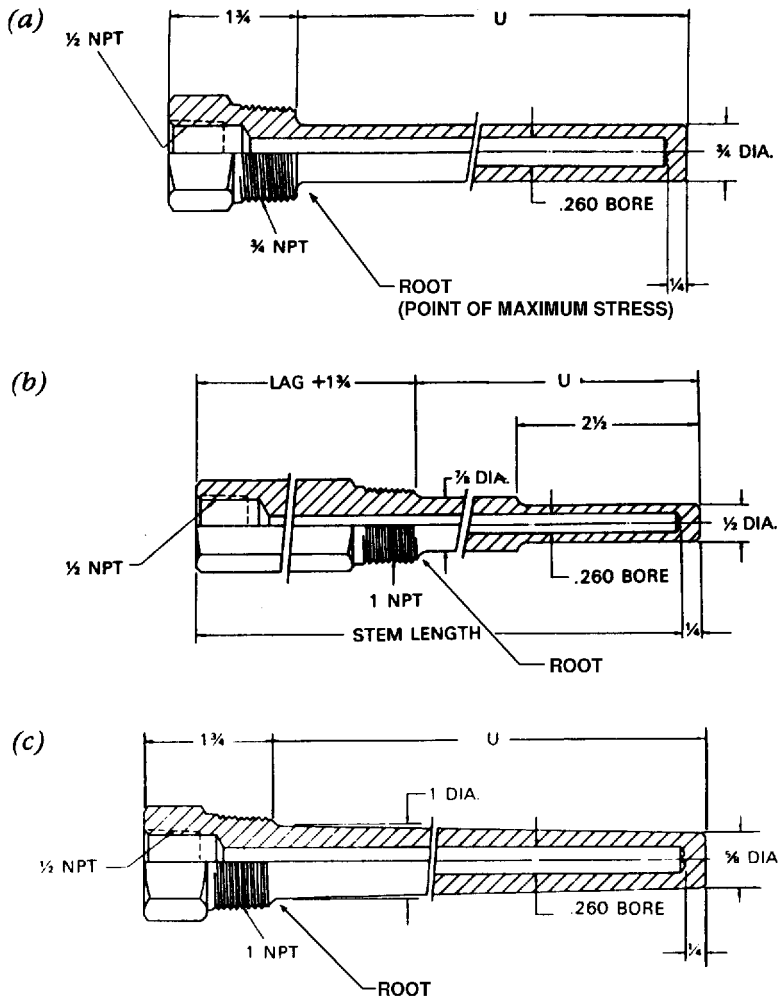

Figure 6: Schematics of Threaded Thermowells for Screwed-On Connection (After McFadden and Assoc.)

13. The second most common connection is flanged. Figure 7 shows a flanged thermowell in the top illustration (a). A standard piping flange is machined on or welded to the thermowell, and a flanged nozzle is provided on the process equipment. Standard flange sizes are DIN 25, 40, and 50 mm (1, $1^1/_2$, and 2 in) with flange ratings to meet the piping specification. Larger flanges can be used by drilling a blind flange and welding a thermowell to it. Flanged thermowells are more expensive than the screwed type. Flanged thermowells are common for corrosive or sour gas service because they offer added security against leaks.

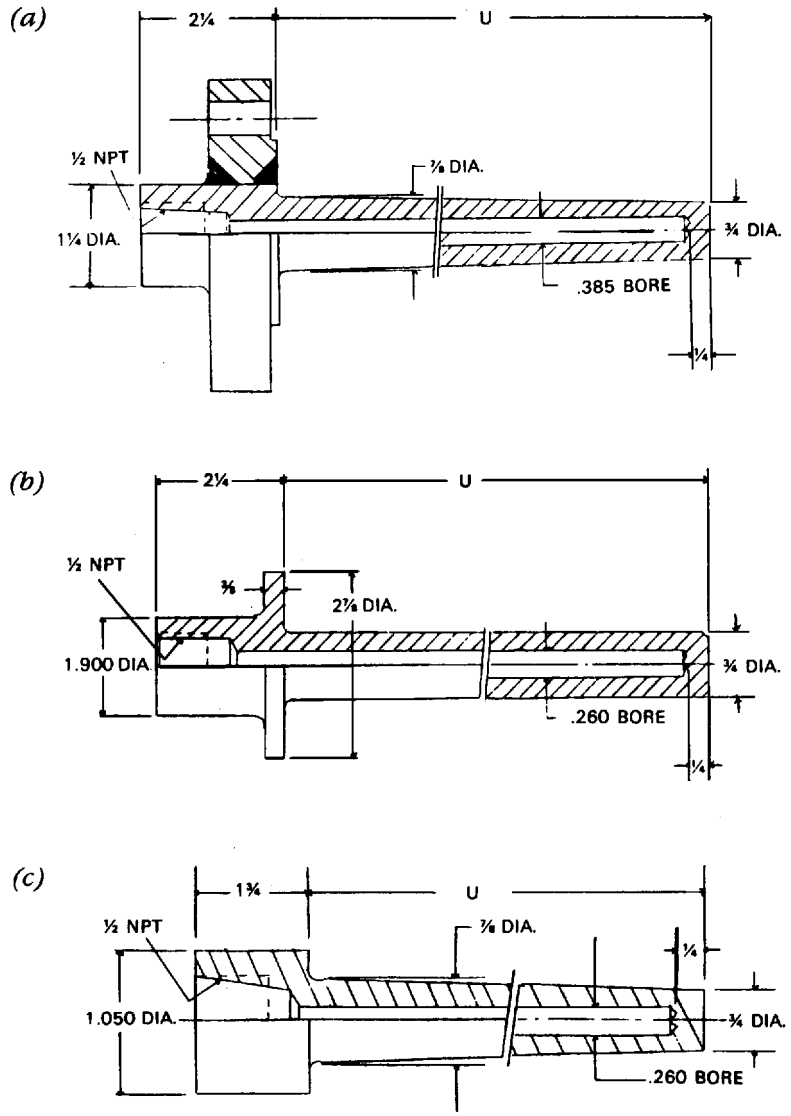

Figure 7: Schematics of Flanged Thermowells and a Socket-Welded Thermowell

14. Van-Stone (or lap joint) flanged thermowells are similar to flanged thermowells, but in this case the well is machined with a lap joint to match the raised face area of a normal flange. A Van-Stone flanged thermowell is shown in the center drawing (b) of Figure 7. In these thermowells, a flange is not welded to the well; instead, a slip-on flange that holds the well in place is bolted over the lap joint.

15. Van-Stone flanged thermowells offer the same advantages as flanged thermowells, with the added advantage of being able to interchange the flange in the field. In addition, the flange can be made of carbon steel, with the rest of the well made of more expensive material. Van-Stone

flanges are more common in chemical plants where the thermowells are made from materials more expensive than stainless steel, but they can be used for production facilities if desired.

16. Socket-welded thermowells are rarely used in production facilities except for attachment through drilled flanges. Figure 7 shows a socket-welded thermowell in the bottom drawing (c). The advantage of socket-welded thermowells is leak prevention. This advantage outweighs the associated inconvenience only when the fluid is very expensive or highly toxic. The most toxic fluid commonly found in production facilities is hydrogen sulfide, which is generally not considered toxic enough to warrant this precaution.

17. Most thermowells used in production facilities are machined from a solid piece of material in a fabrication process generally referred to as "drilled" or "barstock" construction. They can also be made by cutting a piece of drawn tubing, welding the end closed, and then welding on the process connection. This second type is generally known as "welded", "drawn", or "tubing" construction. Drilled construction is more expensive than welded construction, but it is more reliable and durable.

18. Thermowell construction can also be termed "straight", "stepped", or "tapered". These terms refer to the outside shape of the portion of the well that is inserted into the process and are shown in Figure 6. Welded thermowells are available in only the straight and stepped shapes, while drilled thermowells are available in all three. As one would assume, the three shapes are progressively more expensive to machine. The advantage of the tapered well is that the bottom of the well (where the sensor is located) can be thin to improve heat transfer, and the root of the well (subject to maximum torque) can be thicker and thus, stronger. While the tapered shape is ideal, the stepped shape also offers a thin bottom and a heavy root and is easier to machine, but it does not offer continuously increasing strength. The straight well is the least expensive, but the wall thickness shall be a compromise between heat transfer and strength.

19. The length of the thermowell is referred to by a number of terms. Refer to Figures 6 and 7.

    a) Element Length is the depth of the bore measured from the very top of the well to the bottom of the bore. Usually, this dimension is 6 mm ($^1/_4$ in) less than the overall length of the well.

    b) Insertion Length is the length that is exposed to the process fluid. It is the distance from the bottom of the threads, the bottom of the flange, or the bottom of the socket to the tip of the thermowell. Insertion length is also known as the "U" dimension.

    c) Thread Allowance is the threaded length of the thermowell. This is usually 25 mm (1 in). Thread allowance applies only to screwed thermowells.

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d) Wrench Allowance is the length of the wrench flats above the threads. This dimension is usually 19 mm ($^3/_4$ in). Wrench allowance applies only to screwed thermowells.

e) Lagging Extension (or "lag") is the length between the thread allowance and the wrench allowance, allowing the top of the well to be accessed when installed in an insulated pipe or vessel. The lagging extension is usually 75 mm (3 in). This dimension is usually specified only when insulation is present, and it applies only to screwed or socket-weld thermowells. The nozzle for mounting the flanged well protrudes through the insulation, so a lagging extension is not required. The lagging extension is also known as the "T" length.

f) Flanged and Van-Stone flanged thermowells extend above the face to allow for installation of the flange, but there is no special name for this dimension. This dimension is usually about 56 mm ($2^1/_4$ in).

4.1.2. Thermowell Installation

1. The primary objective of thermowell installation is to place the temperature sensor in the process at a location where the reading shall represent the process temperature as accurately as possible. Other objectives are to minimize the disturbance caused by the protrusion of the well and to locate the sensor conveniently. The temperature shall be closer to ambient near the surface of the pipe or vessel and in stagnant areas. The sensor shall be installed as far away from the surface as practical and in an area subject to maximum flow or circulation.

2. Screwed thermowells are installed by welding a threadolet, latrolet, or elbolet to the pipe as shown in Figure 8. It is preferable to install the thermowell perpendicular to the flow. The shortest practical U dimension is 64 mm ($2^1/_2$ in), which makes the smallest usable pipe diameter 75 mm (3 in) nominal for the preferred type, shown in detail (a). Details (b) and (c) show alternative mountings for small line or high velocity applications. Another method is to swage up for a distance large enough to accommodate the well. If the line size is 50 mm (2 in) and screwed, a thermowell can be installed in a reducing tee. The thermowell will cause a significant obstruction in a 50 mm (2 in) line, so this method shall be used with caution.

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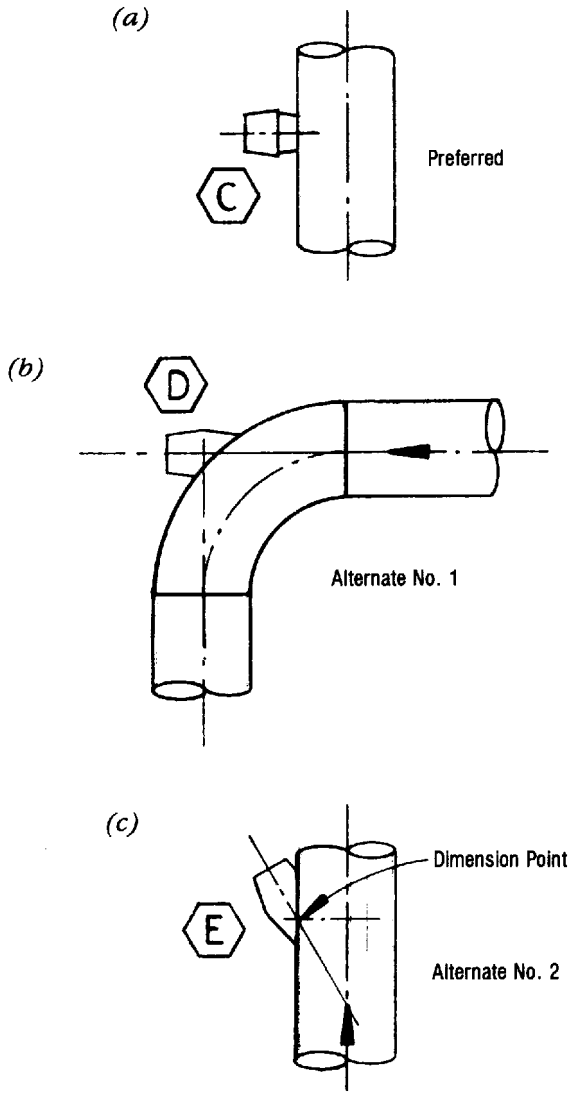

Figure 8: Schematics of Screwed Thermowell Installation Alternatives

3. For temperature measurements in 100 mm (4 in) and larger lines, the thermowell shall be selected to reach or extend slightly past the center of the pipe. For pipes larger than 305 mm (12 in), the velocity of the flowing fluid may cause overstressing of the thermowell. If overstress is a potential problem, the use of a shorter thermowell is usually satisfactory because the flow will be turbulent enough to cause the temperature to be representative fairly near to the wall.

4. Flanged thermowells are subject to the same considerations as screwed thermowells. Typical installations of flanged thermowells in piping are shown in Figure 9. In addition, the length of the nozzle and associated

fitting shall be added to the U dimension that is selected for a screwed thermowell.

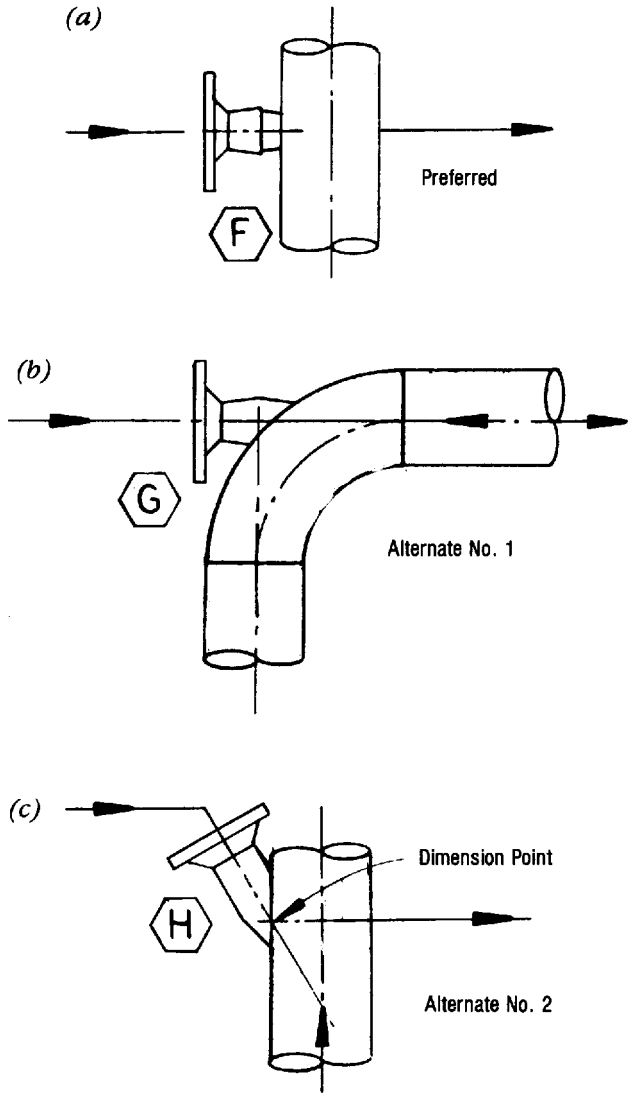

Figure 9: Schematics of Flanged Thermowell Installation Alternatives

5. Thermowells must not be installed in pipes that shall pass a scraper or pig, because the obstruction is unacceptable. Usually it is possible to locate a thermowell before the pig launcher or after the pig receiver, where a protrusion into the line is acceptable.

6. Thermowells shall be installed so that the flow impinges on the bottom of the well (as shown in Figures 8 and 9) for the best reading.

7. Thermowells in pressure vessels usually are not required to reach the center of the vessel. 305 mm (12 in) of protrusion into the vessel is

usually adequate for a good reading. As with flanged thermowells in piping, the nozzle length shall be added to the protrusion in the computation of the proper U dimension. There shall be no interference between internals and the thermowell. For multiphase vessels, the well shall be located so that it is immersed in the fluid whose temperature is to be measured.

8. Test thermowells are often installed at points throughout the process where continuous measurement is not required, but temperature information is needed periodically or during special circumstances. These thermowells are usually 12.3 mm ($^1/_4$ in) bore for dial thermometer insertion or 9.53 mm ($^3/_8$ in) for glass thermometer insertion. A cap or plug is required to keep insects or dirt from the bore.

4.1.3. Thermowell Vibration

1. Fluid flowing past an obstruction, such as a thermowell, forms eddies (vortices) on the downstream side of the obstruction. These eddies, called the "Von Karmin Trail", cause a pressure differential between the upstream and downstream sides of the thermowell which varies at a constant frequency for a given shape and set of flowing conditions. Any structural member that is fixed at one end has a natural vibration frequency. If the frequency of the Von Karmin Trail is equal to the natural frequency of the thermowell, a vibration of the well that is likely to cause failure will result. The general consensus regarding an adequate safety factor is that the natural frequency shall be at least two times that of the Von Karmin Trail. Calculation of these frequencies is possible but fairly complex and usually not needed. Vibration is a problem only in large lines with high flow rates.

2. In addition to withstanding vibration, the installation connection shall be strong enough to withstand the torque caused by the fluid impinging on the thermowell. Thermowell vendors can supply more exact data for their products, but the following guidelines can be used if better data is not available. Some typical vendor ratings are shown in Table 1.

Table 1: Typical allowable velocities for thermowells of various types, dimensions and materials. Values shown are for maximum fluid velocity in feet per second for liquid, steam, or gas. Number in parentheses must be used if liquid is present.

Stepped Thermowell									
Conn. Type	Material	Insertion Length - "U"							
		$2^1/_2$	$4^1/_2$	$7^1/_2$	$10^1/_2$	$13^1/_2$	$16^1/_2$	$19^1/_2$	$22^1/_2$
$^3/_4$" Scr'd.	Brass	207 (59.3)	89.1 (39.8)	32.2 (23.9)	16.4	9.9	6.6	4.8	3.6
	Carbon Steel	290 (100)	123 (71.8)	44.9 (43.7)	22.8	13.8	9.3	6.7	4.9

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		(106)	(71.2)	(42.7)					
	A.I.S.I. 304 & 316	300 (148)	128 (99.3)	46.4	23.6	14.3	9.6	6.9	5.1
	Monel	261 (118)	112 (79.8)	40.6	20.7	12.4	8.3	6.1	4.5
1" Scr'd.	Brass	207 (59.3)	102 (47.6)	37.0 (28)	18.8	11.4	7.6	5.5	4.1
	Carbon Steel	290 (106)	143 (84.3)	51.6 (50.6)	26.2	15.9	10.6	7.6	5.7
	A.I.S.I. 304 & 316	300 (148)	148 (117)	53.5	27.2	16.5	11.0	7.9	5.9
	Monel	261 (118)	128 (93.3)	46.7	23.7	14.4	9.5	6.9	5.1

Tapered Thermowell

Conn. Type	Material	Insertion Length - "U"							
		$2^1/_2$	$4^1/_2$	$7^1/_2$	$10^1/_2$	$13^1/_2$	$16^1/_2$	$19^1/_2$	$22^1/_2$
$^3/_4$" Scr'd.	Brass	305 (97.5)	93.8 (54.1)	33.9	17.1	10.5	7.0	5.0	3.7
	Carbon Steel	386 (175)	180 (97.2)	65.3 (58.3)	33.0	20.1	13.4	9.6	7.1
	A.I.S.I. 304 & 316	440 (243)	197 (135)	71.2	36.0	22.0	14.7	0.5	7.8
	Monel	354 (195)	155 (108)	56.1	28.4	17.3	11.6	7.5	5.6
1" Scr'd.	Brass	354 (161)	108 (89.5)	39.4	19.8	12.2	8.1	5.8	4.3
	Carbon Steel	448 (289)	209 (161)	75.7	38.4	23.3	15.5	11.1	8.2
	A.I.S.I. 304 & 316	490 (403)	228 (225)	82.5	41.8	25.5	17.1	12.2	9.1
	Monel	410 (322)	179 (178)	65.1	33.0	20.1	13.5	8.7	6.5

Straight Thermowell

Conn. Type	Material	Insertion Length - "U"						
		2	4	7	10	13	16	22
Flanged	Carbon Steel	404 (129)	184 (71.2)	67.0 (42.7)	34.0	20.6	13.7	7.4
	A.I.S.I. 304 & 316	430 (179)	192 (99.3)	69.7 (59.6)	35.4	21.5	14.3	7.7
	Monel	350 (143)	168 (79.8)	61 (47.7)	31.0	18.8	12.5	6.7
Flanged	Carbon Steel	410 (152)	248 (84.3)	91.3 (50.6)	45.7	27.6	18.5	10.0

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A.I.S.I. 304 & 316	444 (211)	258 (117)	95.2 (70.3)	47.6	28.8	19.3	10.4
Monel	338 (168)	226 (93.3)	83.3 (56.0)	41.6	25.2	16.9	9.1

3. The general practice for production facilities is to size liquid lines for velocities below 4.6 m/sec (15 ft/sec) and gas lines for below 18.3 m/sec (60 ft/sec). Standard screwed and flanged stainless steel tapered thermowells with U dimensions of 190 mm ($7^1/_2$ in) are generally safe for these velocities. A 190 mm ($7^1/_2$ in) insertion length is generally adequate for pipes of up to 400 m (16 in) if screwed connections are used. If flanged connections are used, a longer thermowell shall be used. Insertion dimensions up to 254 mm (10 in) can be safely used if gas velocities are under 13.7 m/sec (45 ft/sec). Relieving systems and pipelines sometimes exceed these velocities. The manufacturer's applications engineers or literature shall be consulted for specific applications.

4. Fluid velocities in pressure vessels and tanks are generally well under 3 m/sec (10 ft/sec), which is the limitation for insertion lengths up to 560 mm (22 in).

4.2. Bimetallic Thermometers

4.2.1.

Bimetallic thermometers are relatively inexpensive devices. Most pressure vessels and heat exchange devices are equipped with bimetallic thermometers.

4.2.2.

Bimetallic thermometers are easy to read, and their standard 1 percent of full scale accuracy is adequate for most applications. Dial sizes are available from 25 mm (1 in) diameter, which can be carried in a shirt pocket, to 125 mm (5 in) or larger, which are easily read from a reasonable distance. The 125 mm (5 in) size is common for production installations.

4.2.3.

The larger thermometer sizes usually have a male thread for installation in a thermowell. Threads are often optional for intermediate sizes. The most common size thread is 12 mm ($^1/_2$ in) NPT with 6 mm ($^1/_4$ in) and 18 mm ($^3/_4$ in) options. The standard connection is on the back of the thermometer where the face is perpendicular to the stem to allow direct drive of the pointer by the element. For tops of vessels and other situations where a back connected thermometer cannot be easily read, models are available in the larger sizes with bottom stems that drive the pointer through a gear. Thermometers with tiltable dials, often called the "every angle" type, are also

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available where an intermediate position is needed or the needed position is not known. The every angle type is the preferred type for its application in all areas and locations. As one would expect, the plain, back connected, bottom connected, and every angle types are progressively more expensive. These types are shown in Figure 10.

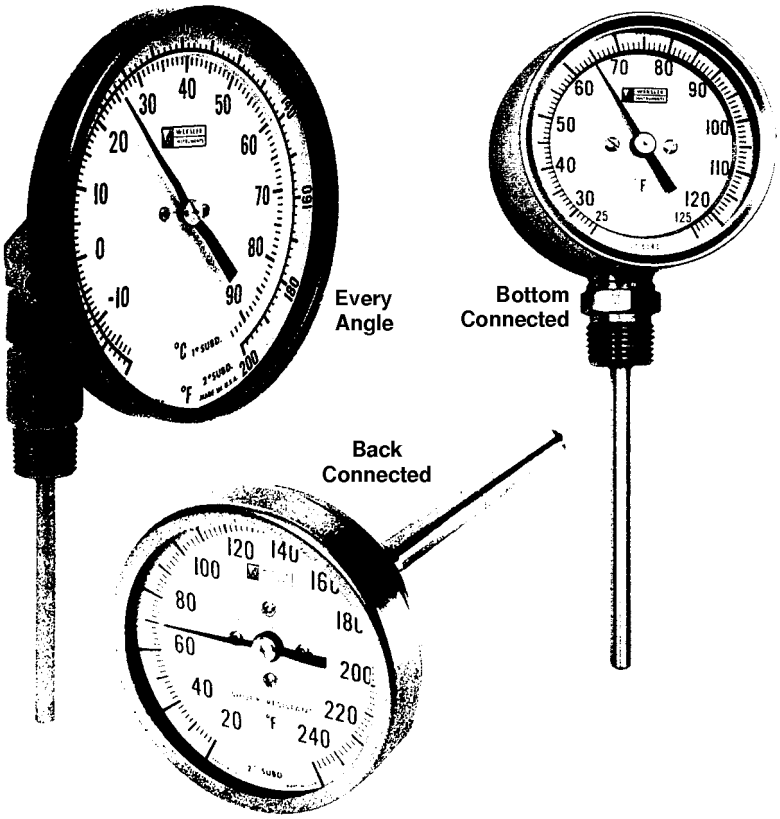

Figure 10: Various Types of Bimetallic Thermometers (Reproduced Courtesy of Weksler Instruments)

4.2.4.

The dial window can be glass, which is scratch resistant but easy to break, or clear plastic, which is harder to break but easier to scratch. Also available are models that are hermetically sealed to prevent corrosion to the internals and to prevent window fogging, but require replacement if the window is broken or scratched excessively. Other models have a removable bezel to allow window replacement but are not well sealed from the atmosphere. Some manufacturers offer liquid-filled models in which the dial is filled with glycerine or silicone, as is common in pressure gauges, for corrosion resistance and vibration dampening. Hermetically sealed or liquid-filled thermometers are usually best for moist or corrosive areas, such as offshore

or near salt water. Replaceable windows may be preferable where physical damage is more likely than corrosion.

4.2.5.

Bimetallic thermometers are available in convenient range increments for measurements between -60°C (-80°F) and 540°C (1000°F). A range shall be chosen so that the normal operating temperature is near the center and both the high and low temperatures of interest are covered. Bimetallic thermometers are not very susceptible to damage from over or under-ranging. Dial calibrations are available in either Fahrenheit or Celsius or with both calibrations. An external adjustment screw is usually provided so that the thermometer can be calibrated at a single point, but there is usually no adjustment for span. Additional information is provided in Section 4.2 of the Chilton Process Measurement Handbook.

4.3. Glass Tube Thermometers

4.3.1.

Glass tube thermometers are sometimes called "yellow back" thermometers because the graduations are often backed by yellow paint for easy reading. They are used in laboratories for calibration and sometimes in custody transfer applications. Reference thermometers are available to read temperature within 0.1°C (0.2°F) over ranges covering from -38 to 650°C (-36 to 1200°F). Several types of glass tube thermometers are shown in Figure 11.

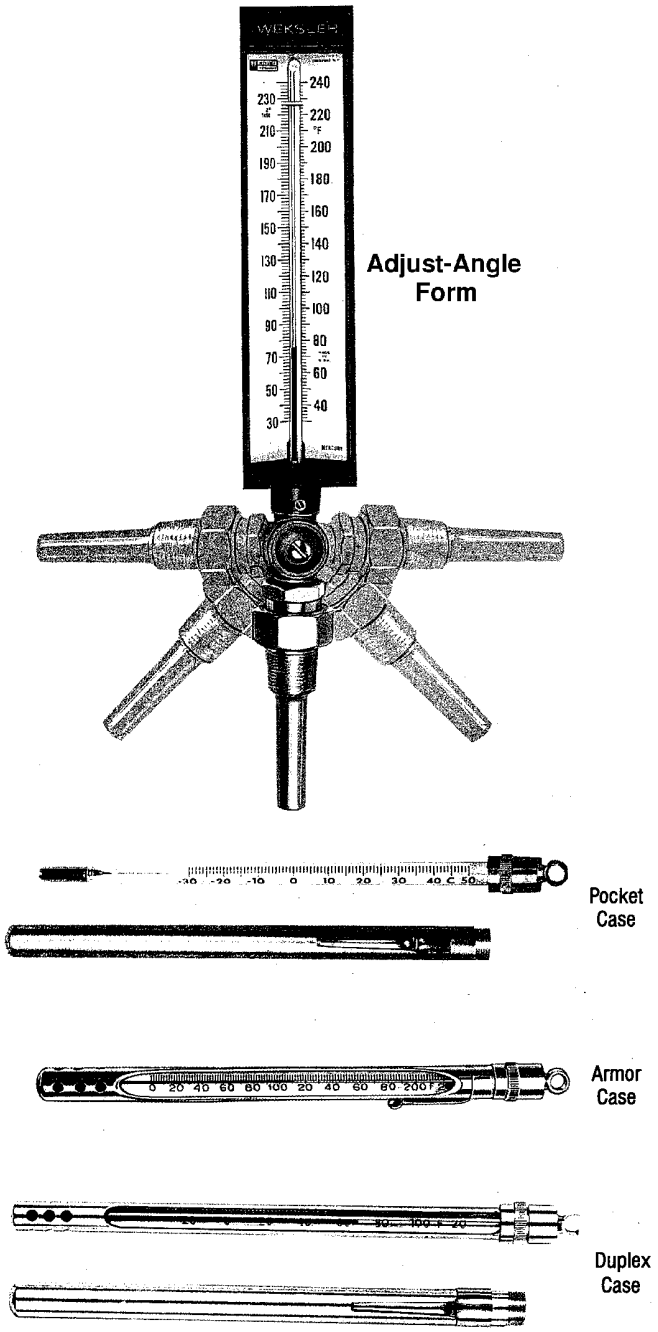

Figure 11: Several Types of Glass Tube Thermometers (Reproduced Courtesy of Weksler Instruments)

4.3.2.

Additional information is provided in Section 4.5 of the Chilton Process Measurement Handbook.

4.4. Digital Thermometers

4.4.1.

Electronic digital thermometers are available in a number of forms. The most common type is battery-powered and hand-held with a resistance temperature detector (RTD) or thermocouple probe. The probe can be inserted into a thermowell or other area that is to be measured. Approximate readings can be made by holding the probe in contact with the surface of a pipe or vessel. The resolution and accuracy of these instruments typically range between 0.1 and 1 degree Fahrenheit or Celsius.

4.4.2.

Weatherproof and intrinsically safe digital thermometers are available for field mounting. They are usually battery-powered and have liquid crystal displays. They can be self-contained with a thermocouple or RTD probe, or can be connected to a remote sensor. They are practical devices if frequent readings with one degree or better resolution are needed, but they require more maintenance than dial thermometers. A digital thermometer for field mounting is shown in Figure 12.

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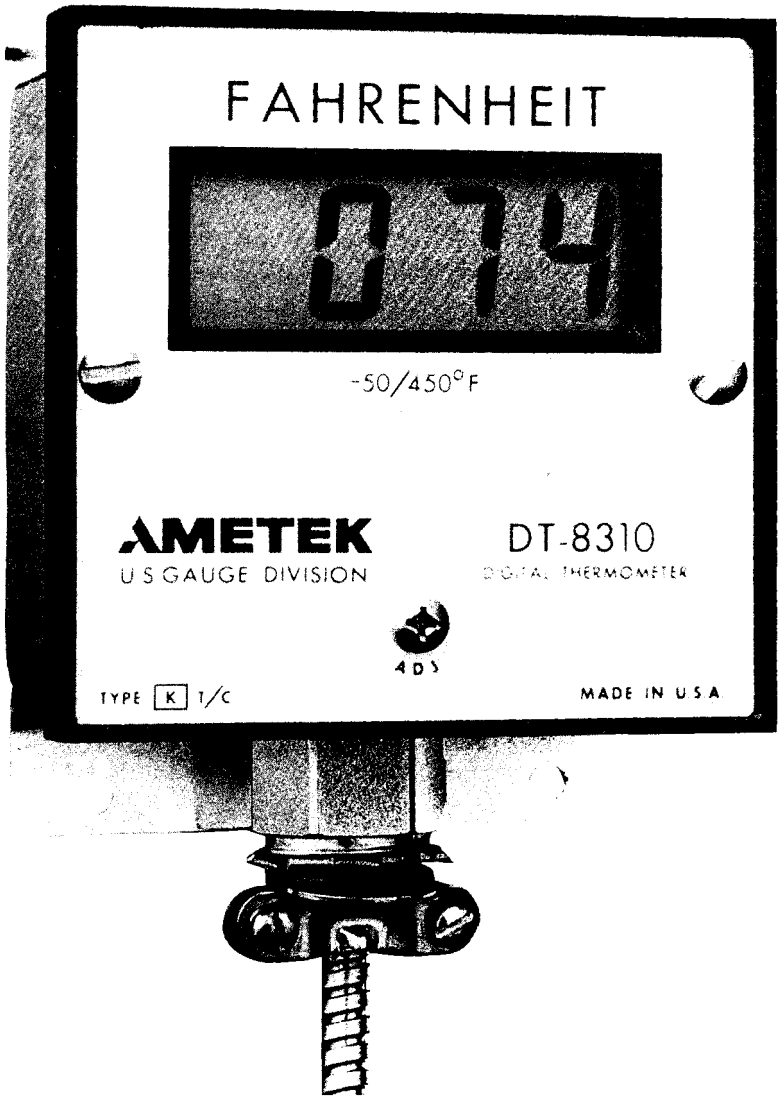

Figure 12: Digital Thermometer for Field Mounting (Reproduced Courtesy of Ametek)

4.5. Filled-System Thermometers

4.5.1.

The accuracy of a filled-system thermometer is about the same as a bimetallic thermometer, and filled-system thermometers are much more expensive. Therefore, filled-system thermometers are not usually used unless remote installation of the gauge is desired. Figure 13 shows some typical filled-system thermometers.

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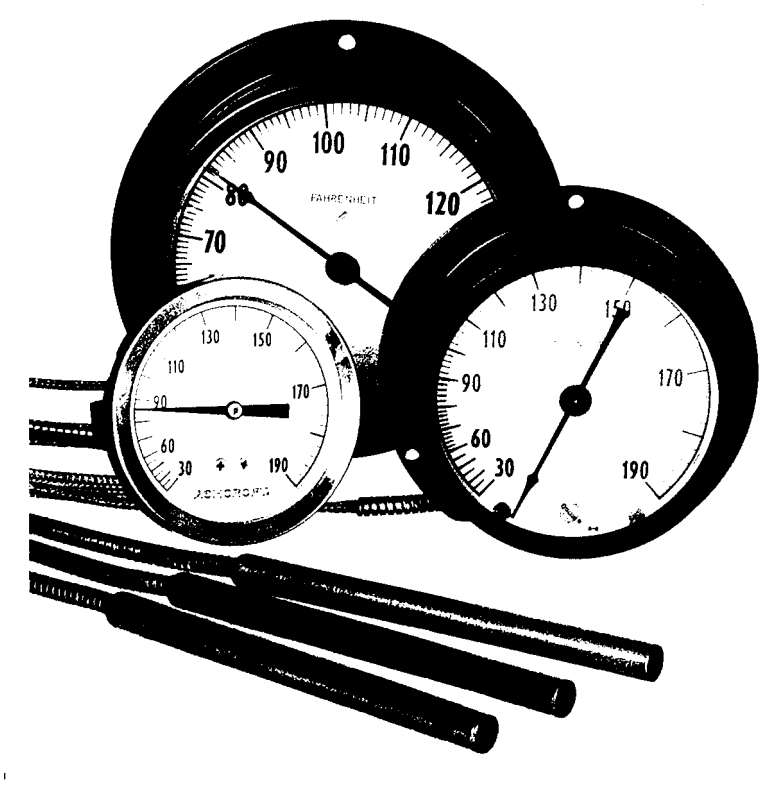

Figure 13: Filled-System Thermometers (Reproduced Courtesy of Ashcroft, Dresser Industries)

4.5.2.

More information is available in Section 4.4 of the Chilton Process Measurement Handbook.

4.6. Infrared Pyrometers

4.6.1.

Infrared pyrometers are not used for ordinary process measurement or control, but can be very useful for trouble spotting. Defective stack, bearings, transformers, and other devices where increased temperature is a symptom of the malfunction can be spotted without actually contacting the location. Figure 14 shows a pyrometer with a stock and telescopic sight for aiming like a rifle.

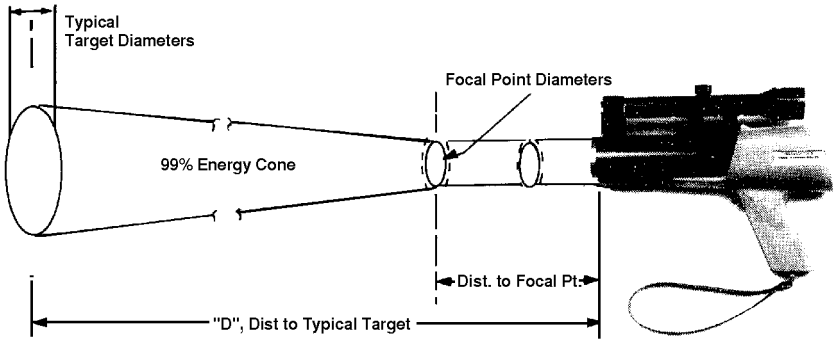

Figure 14: Infrared Pyrometer Used to Sense Temperature at a Distance (Reproduced Courtesy of Omega Engineering, Inc., an Omega Technologies Co. Copyright 1988 All Rights Reserved)

	Min. Target Distance		Focal Point		Target Size
	Distance	Target Dia.	Distance	Target Dia.	Beyond Focal Point
90% energy cone	36"	.58"	78"	.67"	Targeted Dist/120
99%	36"	.9"	78"	1.34"	Targeted Dist/60

4.6.2.

More information is available in Section 4.8 of the Chilton Process Measurement Handbook.

4.7. Resistance Temperature Detectors

4.7.1.

Resistance temperature detectors (RTDs) are the most frequently used electronic temperature sensors for production facilities. RTDs are not quite as rugged as thermocouples, but they are superior in interchangeability, repeatability, accuracy and linearity. They are suitable for temperature measurements from - 240°C (-400°F) up to 650°C (1200°F). The cost of the sensor is approximately twice that of a thermocouple, but after the costs of the thermowell and receiver units are added, the additional cost per measurement is about 10 percent.

4.7.2.

The industry has standardized on RTDs that are calibrated to DIN standard 43760, which is also known as the European standard. RTDs that meet this standard measure 100 ohms at 0°C, are made of platinum, and exhibit a resistance increase of 0.385 ohms per C increase. Another standard, called

the American standard, is available but is not in wide use, even in the United States.

4.7.3.

RTDs are usually purchased as a probe assembly consisting of the RTD sensor installed in a type 304 stainless steel sheath. The sheath is held in the thermowell by a spring-loaded fitting that is threaded on both ends for attachment to the thermowell and the head so that the tip of the sheath touches the end of the well. The spring holds the sheath firmly against the bottom of the well for good heat transfer. Another method is to silver solder the sheath into the fitting, which makes a good firm assembly but requires a small clearance from the bottom of the well. The third popular method has a compression fitting so that the sheath can be pushed against the bottom of the well after the fitting is screwed into the well. The compression nut is then tightened to hold the sheath. The compression fitting allows use of a universal probe in different lengths of thermowells. Figure 15 shows these methods for sheath attachment.

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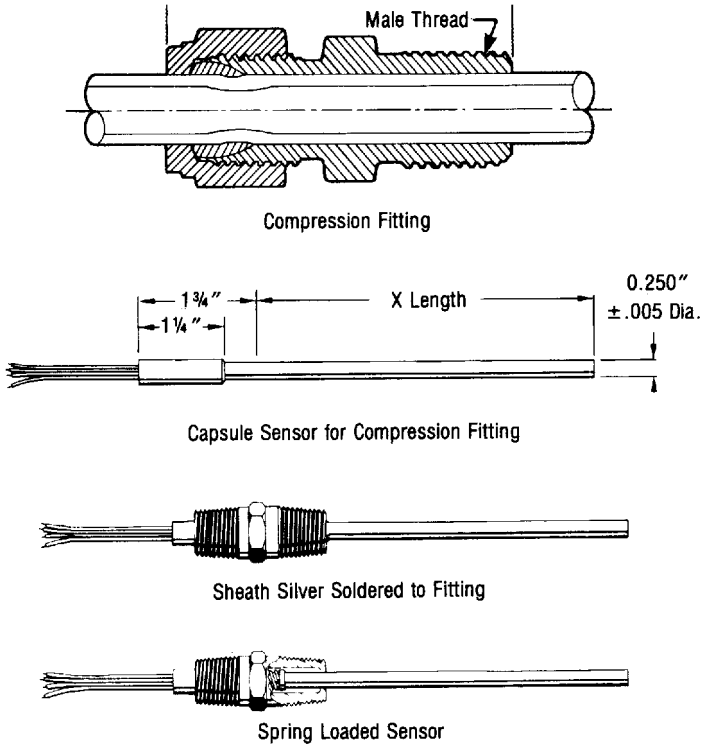

Figure 15: Various Methods for Attaching an RTD or Thermocouple Sheath to a Thermowell Fitting (Reproduced Courtesy of Rosemount Inc.)

4.7.4.

The most common RTD assembly is the nipple-union-nipple assembly, shown in Figure 16. The head of the assembly is a chamber where the leads from the RTD and the leads to the receiver instrument can be terminated and connected to each other. The head has these terminals, a cover so that the terminals can be accessed, a female fitting for attachment of the probe, and a conduit hub. The hub is either cast aluminum or cast iron. The hub can be screwed directly onto the sheath fitting if desired or attached using a pipe nipple and a union. The nipple- union-nipple method of attaching the hub allows changing the sensor without disassembling the conduit if a flexible conduit connection is used. If a union is not used in the temperature probe assembly, one shall be used in the conduit assembly to allow the probe to be removed.

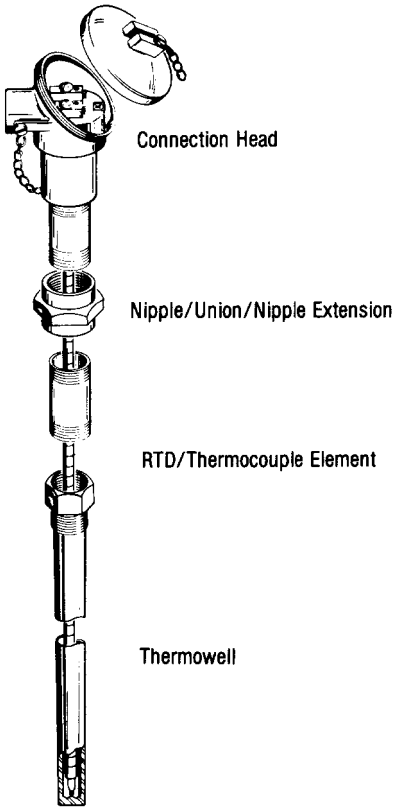

Figure 16: A Nipple-Union-Nipple Extension Assembly for Installing an RTD or Thermocouple Element into a Thermowell (Reproduced Courtesy of Omega Engineering Inc. and Omega Technologies Co. Copyright 1988, All Rights Reserved.)

4.7.5.

Some RTDs are constructed by winding platinum wire around a form, and others are formed by depositing platinum film on an alumina substrate. The deposited type is a recent development that has decreased the cost of RTDs without sacrificing performance. Either type is acceptable for general production facility use. RTDs manufactured for sensing winding temperatures in electric motors are long and flexible. These RTDs can measure the average winding temperature much better than devices such as thermocouples, which measure only a spot temperature.

4.7.6.

More information on RTDs can be found in Section 4.11 of the Chilton Process Measurement Handbook.

4.8. Thermocouples

4.8.1.

Thermocouples offer low cost, high reliability, and good measurement characteristics. Temperature ranges are from -268°C (-450°F) up to 2316°C (4200°F). This wide range makes them suitable for applications such as exhaust stacks and flare pilot monitors.

4.8.2.

Thermocouple probe assemblies offer the same options as those for RTDs. Refer to the previous section and the section on thermowell selection for details. Like RTDs, the usual sheath material is stainless steel; however, other materials are used when the temperature is expected to be above 870°C (1600°F). Inconel is usually used when maximum expected temperature is above 870°C (1600°F) and below 1150°C (2100°F). Alumina or ceramic sheaths can be used for higher temperatures. The temperature in the flame area of fired equipment ranges from about 870°C (1600°F) to 1540°C (2800°F), but there is rarely a need for a measurement of this temperature in production facilities. The most severe service normally encountered is pilot monitors for fired equipment and flares. There is no need to place the thermocouple in the hottest part of the flame; 304 stainless steel is adequate if the sensor is placed in a cooler part of the flame or only partially in the flame.

4.8.3.

The three common thermocouple construction types are illustrated in Figure 17. Exposed junctions offer the fastest response but are not used in oil and gas processing because they are subject to physical damage; in addition, they would need to be installed without a thermowell to take advantage of this faster response. Grounded junctions offer faster response than ungrounded junctions because the contact area that provides the electrical connection also provides good thermal conduction. Grounding at the thermocouple also provides the most nearly symmetrical circuit, which reduces interference picked up by the wires to a minimum. Grounded thermocouples shall be selected unless other components of the circuit require that the ground be at some other point, or unless the process fluid and piping are not at ground potential. Grounding any measurement loop at more than one point usually causes measurement errors because of potential differences in the grounding system. These errors are more acute with low voltage signals such as those generated by thermocouples. These statements do not preclude grounding the extension wire shield at the receiver, which is recommended.

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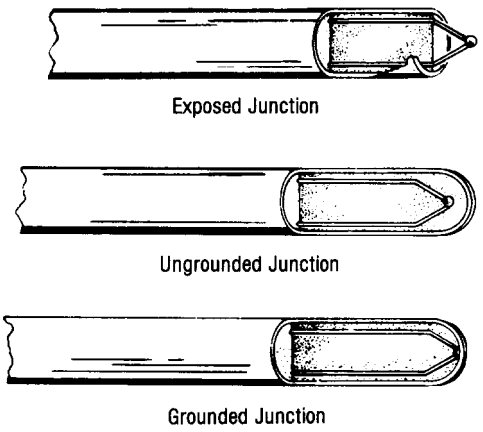

Figure 17: Three Basic Types of Thermocouple Assemblies (Reproduced Courtesy of Omega Engineering Inc. an Omega Technologies Co. Copyright 1988, All Rights Reserved.)

4.8.4.

It is common for two or more thermocouples to be installed in a single sheath. Usually, only one of the sensors is connected to the receiver, with the others used as non-connected spares. This practice is most useful when the sensor probe is difficult to change, such as on a stack or in a cold process where the probe may be frozen in place. Sometimes the sensor is wired only to the head, or it may be continued to a terminal strip in a convenient location. The additional cost for double or triple sensors is usually modest.

4.8.5.

The most common and least expensive thermocouple is iron versus constantan (ISA type J). Type J can be used for measurements from -195°C (-320°F) to 760°C (1400°F) but is normally limited to 0 to 95°C (32 to 200°F). Type J is usually furnished when no specific type is specified. It is sometimes referred to as a 30 mv thermocouple because its output is approximately 30 mv at 540°C (1000°F) when compared to an ice point reference. The main drawback to type J is that the iron wire oxidizes readily, limiting its life in most atmospheres.

4.8.6.

Chromel versus alumel thermocouples (ISA type K) offer better corrosion resistance, and the increase in price is negligible for thermocouple assemblies. Type K is also more resistant to high temperatures and has a higher usable temperature. Type K can be used for -210°C (-350°F) to 1370°C (2500°F) but is usually limited to 0 to 1100°C (32 to 2000°F). Type K does not produce as much output as type J, i.e., it produces only 22 mv at

540°F (1000°F). Direct substitution of type K for type J shall be done with caution because of this large difference in output curves.

4.8.7.

Copper versus Constantan thermocouples (ISA type T) are usually used when temperatures below zero are to be measured. While the usable range for type T, -190 to 400°C (-310 to 750°F), is the same for the lower limit and less for the higher limit than for types J and K, the recommended range is -180 to 370°C (-290 to 700°F). The materials used in type T behave more predictably at low temperatures than those used for types J and K.

4.8.8.

Chromel versus Constantan thermocouples (ISA type E) provide the largest voltage change per temperature change for standard thermocouples. An output of 40 mv at 540°C (1000°F) can be compared to 30 mv for type J and 22 mv for type K. Type E can be used for -195 to 1000°C (-320 to 1830°F) and is recommended for 0 to 870°C (32 to 1600°F). Some sources extend this range downward to -73°C (-100°F), but type T is generally considered a better choice for temperatures below freezing. Type E has more of a tendency to change characteristics with time than types J, K, and T.

4.8.9.

These four types of thermocouples comprise the "base metal" thermocouples. Output versus temperature curves for these types are presented in Figure 18. While the cost may vary somewhat when these types are purchased in bulk, the cost when purchased as practical assemblies is usually the same, so cost is not a selection factor. It is generally agreed that type T is the best choice for temperatures below freezing. Although consensus is not so strong for selection from types J, K, and E for above freezing applications, type K is recommended unless circumstances point to one of the others. Mixing of thermocouple types shall be held to a minimum because ensuring proper receiver calibration can be a problem.

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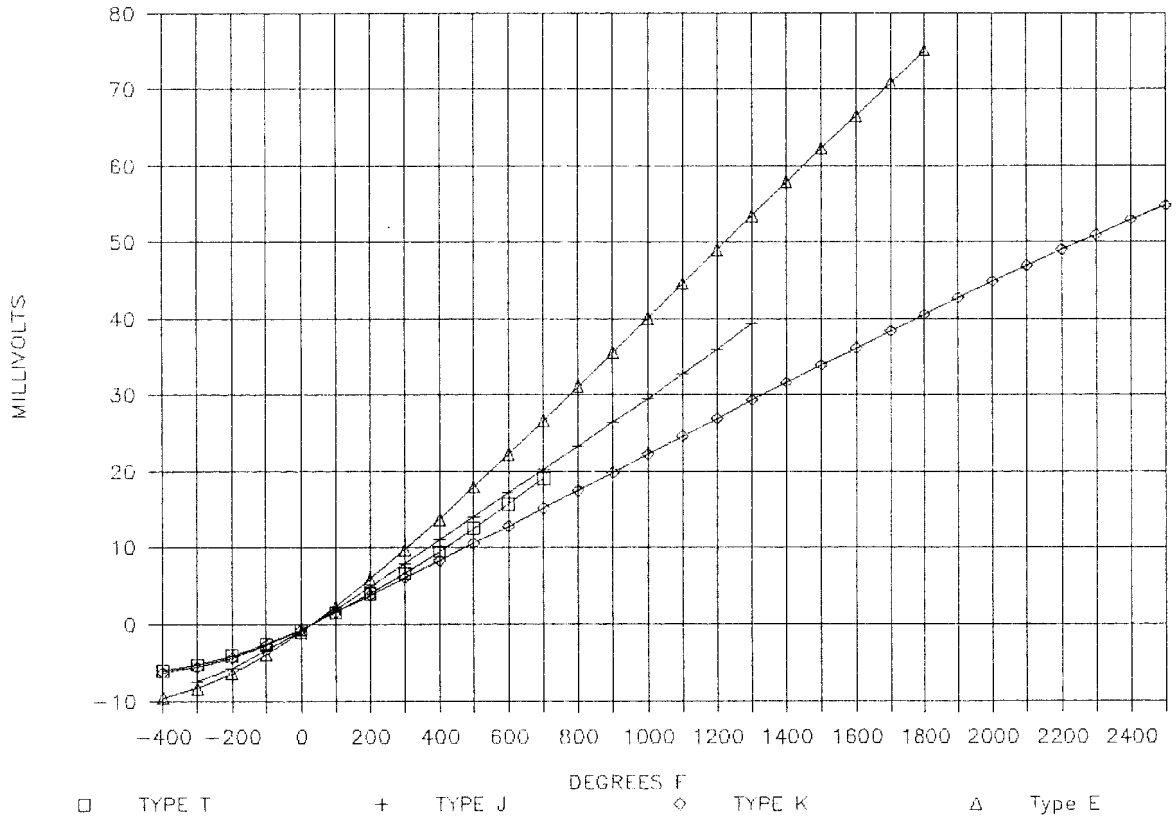

Figure 18: Output Versus Temperature Curves for the Four Types of Base Metal Thermocouples (Types J, K, T, and E)

4.8.10.

Other thermocouple types, called the "noble metal types", are available for measurements where the "base metal" types are not suitable. They are made from expensive metals such as platinum, rhodium, iridium, and tungsten, and thus are more expensive. In addition, they do not provide as much output as the base metal types. These noble metal thermocouples are used in laboratories, for molten metals, and for other applications, but they are rarely used in production facilities.

4.8.11.

With correct connections, copper extension wire can be used over long distances for most thermocouples, since virtually all measuring units or transmitters have built-in cold joint compensation adjustments. However, it is preferred to use the same lead types for iron-constantan or copper-constantan. Multiple input devices such as alarm units and signal multiplexers are available for either field or panel mounting. However, the most common configuration is the combination unit which includes the

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thermocouple, associated thermowell and signal converting transmitter. This type of unit eliminates the problems associated with thermocouple lead wires since the transmitter provides a 4-20 mA signal to the receiving unit.

4.8.12.

More detailed information is available in Section 4.14 of the Chilton Process Measurement Handbook.

4.9. Temperature Switches

4.9.1. Electric

1. Most electric switches can be used as either high temperature or low temperature sensors, depending on how they are calibrated and electrically connected. Electric switches fall into two main functional categories, mechanical and electronic. Electronic switches are also called "solid state" switches because solid-state electronic circuits are used instead of fluids in sensing bulbs.

2. Mechanically operated electric temperature switches are used more frequently in production facilities than the electronic type. They are less expensive and are adequate for most applications. Most mechanically operated electric temperature switches use a vapor-filled system (in which a volatile liquid produces a varying amount of vapor depending on temperature) or a liquid-filled system to operate a pressure switch. Gas-filled systems generally do not develop enough power for switch use. A vapor-filled system temperature switch is shown in Figure 19.

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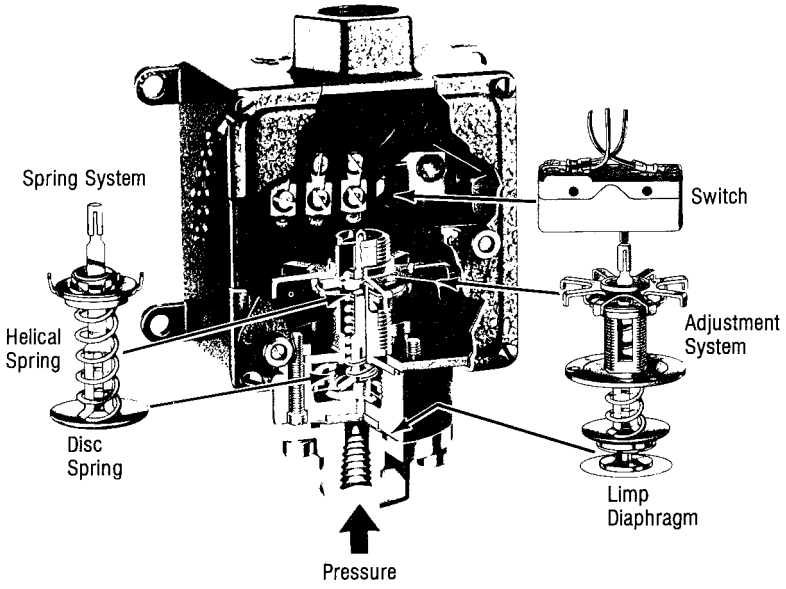

Figure 19: A Mechanically Operated Vapor-Filled System Electric Temperature Switch (Reproduced Courtesy of Custom Control Sensors, Inc.)

3. Various types of fluids are used for fills to provide different temperature ranges, but manufacturers usually state only whether vapor pressure liquid fill is used and the range over which satisfactory operation can be expected. Each method is used with satisfactory results; therefore, the user shall select a switch from the published range and accuracy characteristics rather than by principle of operation.

4. Filled-system switches are available for both local and remote mounting. The local mounting type has the bulb rigidly attached to the switch mechanism and housing. The assembly has a threaded connection so that it can be screwed into and be supported by a thermowell. The remote mounting type has the bulb connected to the switch mechanism by a capillary tube from 2 m (6 ft) to 8 m (25 ft) or more long. The local mounting type is less expensive to purchase and install, while the remote mounting type provides more convenient access and isolation of the switch from process vibration. The switch cannot be separated from the bulb in the field for either of these designs.

5. A disadvantage of mechanically actuated electric temperature switches is significant deadband. When a temperature switch trips on rising or falling temperature, it does not reset at exactly the same temperature as that at which it tripped. The difference is called the "deadband" or "reset". A switch shall be selected so that it shall reset when conditions return to a desired normal range. While the deadband of mechanically activated electric temperature switches is narrow enough to be satisfactory in most applications, sometimes the required trip point is

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very near the normal operating temperature. In these cases, a solid state temperature switch shall be used. The manufacturers' literature usually states the deadband for a particular model.

6. Another disadvantage of mechanically actuated electric temperature switches is that the mass of the bulb and filling fluid takes longer to stabilize at a new temperature than solid-state sensors. Mechanically activated switches are fast enough for most production applications, but a solid-state switch is a better choice if the speed of measurement is critical.

7. Bimetallic elements can also mechanically activate electric switches. The household thermostat and some fire sensors are examples of bimetallic elements. Bimetallic sensors usually are not used for process applications in electric switches because many designs are subject to vibration.

8. Some models of mechanically actuated switches can sense as low as -85°C (-120°F), while others can have trip points as high as 540°C (1000°F). Different fill fluids must be used to obtain different ranges; consequently, a particular switch will operate over only a small portion of this range. Here again, these switches shall meet the vast majority of production applications, but if higher or lower trip temperatures are required or a wide range of adjustment is needed, solid- state switches may be required.

9. Solid-state electric temperature switches use a resistance temperature detector (RTD), a thermocouple, or a thermistor to detect the temperature and contain the required amplifiers and other electronic circuitry to activate a relay or solid- state output device at the set temperature. They can be housed for mounting in the field or, more frequently, for mounting in a rack in a control room or other non-hazardous area. Most solid-state switches are purchased separately from the sensor, but some field-mounted units include the sensor. Figure 20 shows a solid-state switch for control room mounting.

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Figure 20: Typical Solid-State Electric Temperature Switch (Reproduced Courtesy of Rochester Instrument Systems)

10. Solid-state switches can be adjusted for any temperature that can be sensed by a thermocouple, RTD or thermistor. Trip points from -185°C (-300°F) to 1370°C (2500°F) can be accommodated with proper sensor selection. The deadband can be set for well under one degree, or as wide as desired. The response time is significantly shorter than with the mechanical type.

11. The disadvantages of solid-state temperature switches are that they are more expensive and more complicated to install. Either the switch shall be installed in an explosion-proof enclosure, or it shall be located in a non-hazardous area and the sensor wired to it, or additional wires for the power shall be run to the field.

12. Electric temperature switches usually do not have any wetted parts because the thermowell protects them from the process fluid. Most industrial switches are constructed of materials that are suitable for direct immersion and substantial pressure, but this capability is not usually used in production facilities for the reasons mentioned in the thermowell section. The material of construction shall, however, be suitable for exposure to the atmosphere. The most common materials are stainless steel, copper, and brass with stainless steel the most used. The term

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"materials" includes bulb material, capillary material, sheath material, and armor for capillaries.

13. The output from the electric temperature switch is usually either a microswitch or a relay. The contact configuration is most often either single-pole, double-throw (SPDT) or double-pole, double throw (DPDT). DPDT switches are preferred in most cases, as they offer significant control flexibility.

14. Electric temperature switches are also available with two SPDT switch mechanisms operated by a single temperature sensor and with each switch having an adjustable trip point. Such a configuration is used in cases where, for example, two pumps are to be activated at two different temperature set points. It is not practical to adjust this type of switch for use where truly simultaneous operation is required, as in the activation of a shutdown and its alarm. A DPDT switch, or a pair of SPDT switches activated simultaneously by a snap disk (also called a Bellville spring), is used in such cases.

15. The switch housing shall be selected to be suitable for its environment. Many of the switches used in production facilities are installed in a hazardous environment. The manufacturer's literature states whether the switch is approved for hazardous atmospheres. Hydrocarbon processing facilities are in either Division 1 or Division 2 of Class I, Group D. Switches installed in non-hazardous areas need not be explosion-proof but may need to be weatherproof if installed outdoors. Figure 21 shows temperature switches with various types of housing.

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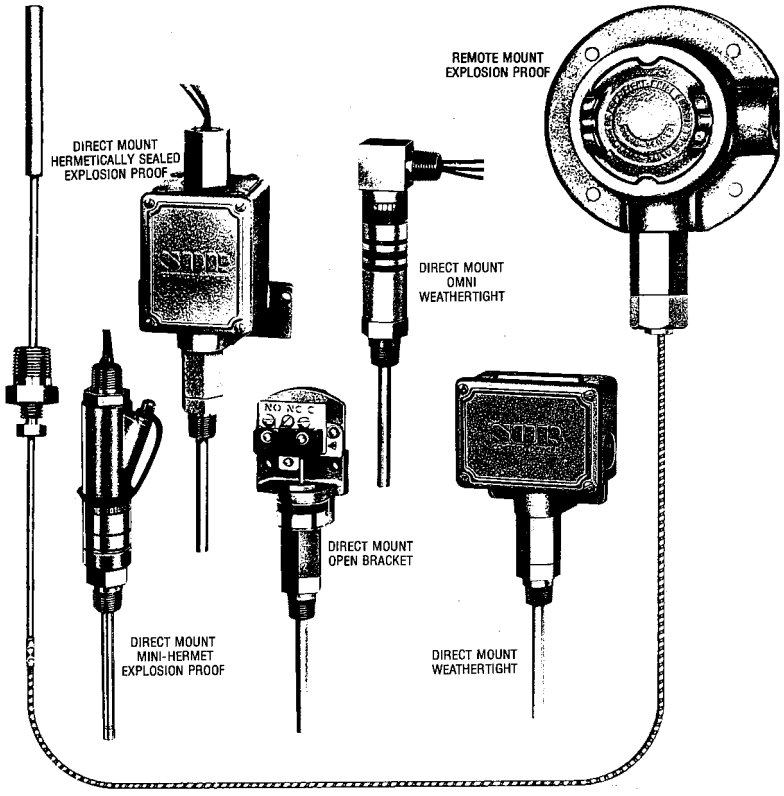

Figure 21: Temperature Switch Housings for Various Installations (Reproduced Courtesy of SOR, Inc.)

16. Additional information is available in Section 4.12 of the Chilton Process Measurement Handbook.

4.9.2. Pneumatic

1. Pneumatic switches are not as abundant as electric switches, but they are still available from several sources. Some manufacturers substitute an air relay for the microswitch in a mechanically actuated temperature switch. Others have a special product for pneumatic applications.

2. The pneumatic temperature switches that are essentially converted electrical switches use the same principles of operation as do their electrical counterparts. Those designed for pneumatic applications are often called temperature valves. They are manufactured with both two-way valves and three-way valves. The two-way type is designed so that a vent port opens when the temperature exceeds the set point. The three-way valve type either connects the receiver device to the pressure source or vents it, depending on the temperature. These units use the bimetallic principle. A typical temperature valve is shown in Figure 22.

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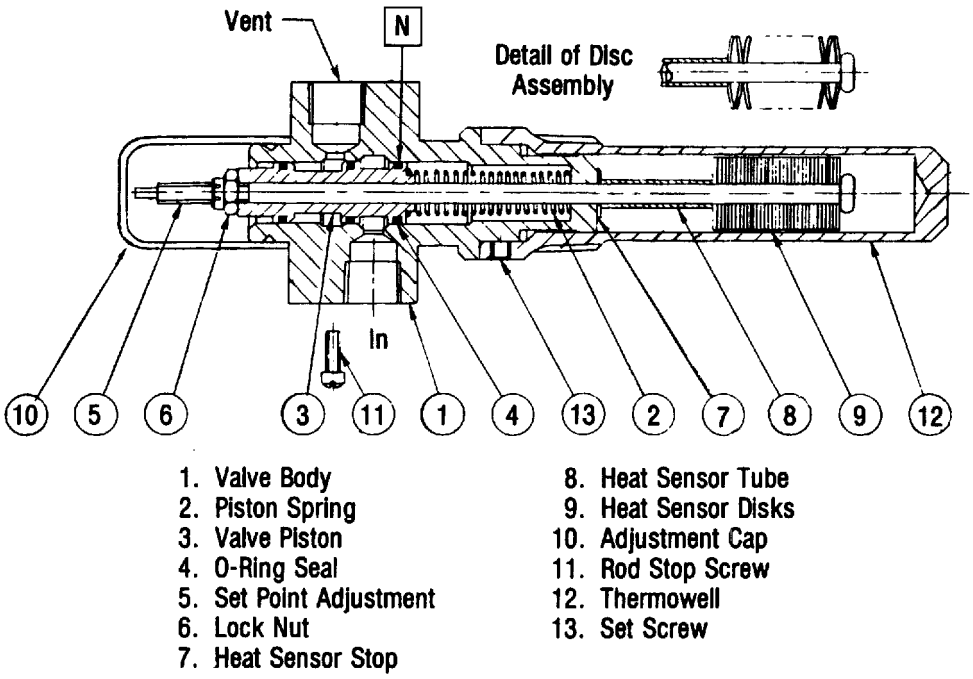

Figure 22: Typical Pneumatic Temperature Valve (Switch) (Reproduced Courtesy of AMOT Controls Corp.)

4.10. Temperature Transmitters

4.10.1.

Temperature transmitters are used when it is necessary to convert the signal from a temperature sensor to one of the standard signals for transmission over a long distance or for interfacing with other instruments. The signal is usually 4 to 20 mA for electronic transmission and 20 to 100 kPa (3 to 15 psig) for pneumatic. Other signals can be used if required by the receiver, but these just specified are the most common and shall be used if possible. It is also possible to bring a temperature measurement into a control room without using a transmitter. A thermocouple or RTD can be wired directly to an instrument in the control room.

4.10.2.

Temperature transmitters can be mounted in the field and on the thermowell or in the field on a support and connected to the sensor by a cable. Figure 23 shows a typical temperature transmitter suitable for field mounting. Temperature transmitters can also be rack-mounted in the control room and wired to sensors distributed around the facility. Control room mounted temperature transmitters are similar to the temperature switch shown in

Figure 20. The electronic circuitry is similar for these three options; the primary differences are in housings and wiring practice. There is no clear advantage to any of these methods in reliability, accuracy, or cost, except that thermowell-mounted transmitters are not a good idea if the pipe vibrates.

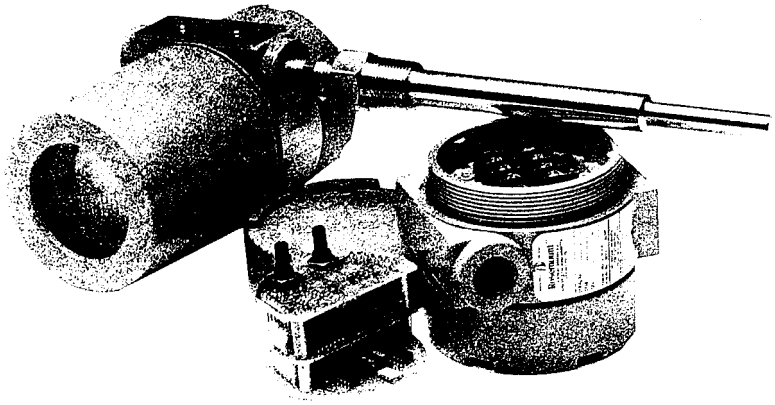

Figure 23: Typical Temperature Transmitter Designed for Field Mounting (Reproduced Courtesy of Rosemount Inc.)

4.10.3.

The type of sensor to be used must be known before the transmitter can be purchased. A transmitter built for use with a thermocouple will not work with an RTD. A transmitter built for one type of thermocouple will work with another type of thermocouple, but the input/output curve shall not be correct, and the measurement will not be accurate. RTD transmitters will also give inaccurate readings if used with the wrong type of RTD.

4.10.4.

Pneumatic temperature transmitters are usually mounted off the process piping and connected to a bulb sensor by a capillary. Pneumatic transmitters are still available from some companies, but their use is infrequent.

4.10.5.

Several companies offer microprocessor-based temperature transmitters, sometimes called "smart transmitters". These transmitters can be remotely programmed and/or calibrated for any desired range, either by the main process computer or by a special programmer. These transmitters are usually used in Distributed Control System (DCS) applications.

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4.11. Temperature Controllers

4.11.1.

A temperature controller is a device that senses temperature and manipulates an end device to control that temperature. The sensor is one of the types covered in the "Principles of Operation" (Section 3). The end device can be a control valve to control fuel or flow through an exchanger, a powered louver, speed control for a fan, or other device.

4.11.2.

The output is usually a 20 to 100 kPa (3 to 15 psig) or 40 to 200 kPa (6 to 30 psig) pneumatic signal, but sometimes is an electric signal (4 to 20 mA) converted by a transducer or solenoid valve to a pneumatic signal.

4.11.3.

A more extensive discussion of control modes and controller tuning can be found in the tutorial EPT 05-T-02 on Controllers and Control Theory.

4.12. Temperature Recorders

4.12.1.

Two basic types of instruments are available, local recorders and remote recorders. Local temperature recorders are often used in conjunction with flow and pressure recorders for custody transfer of fluids. These recorders usually incorporate filled system sensors that mechanically position an ink pen over a circular chart. The chart rotates under the pen to record the temperature for a 24 hour or 7 day period. The chart can be driven by a spring mechanism, electric clock motor, or compressed air. Figure 24 shows such a recorder.

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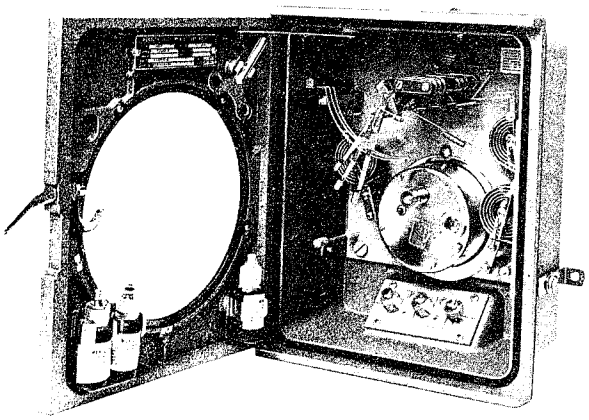

Figure 24: A Filled System Temperature Recorder with Clock Driven Circular Charts: Internal View of a Three Pen Recorder with Spring Drive Mechanism (Reproduced Courtesy of Weksler Instrument Corp.)

4.12.2.

Recorders that mount on a control panel and use RTD or thermocouple sensors are also used. These instruments can accept the input of either a single sensor or multiple sensors. Recorders which can accept the input of up to 25 or more sensors are available. The recorder rapidly sequences through the connected points, recording each frequently enough to form a continuous track. Different colors and/or numbered tracks are used to distinguish between sensors. A data logger is a variation of a continuous temperature recorder which prints the time, point number, and temperature for each point as it sequences through periodically. A multipoint remote temperature recorder is shown in Figure 25.

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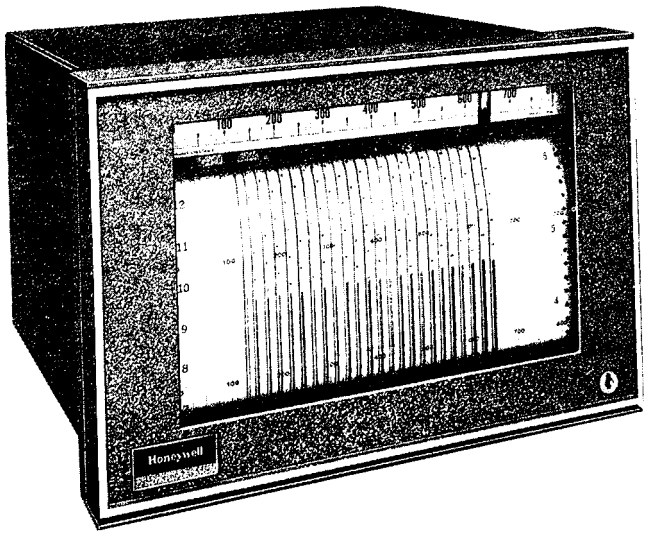

Figure 25: A Multipoint Remote Temperature Recorder (Reproduced Courtesy of Honeywell Inc.)

5. Sensor Testing and Calibration

5.1.

Calibration of temperature instruments is not difficult, but it can be very time consuming. A very common error is not to allow sufficient time for the instrument and the reference standard to stabilize at the test temperature. Several minutes is usually required for each test temperature.

5.2.

Commercial temperature calibrators that make calibration faster and more convenient are available. These devices have a thermowell to receive the sensor and a method to heat a medium around the well. The temperature indicated by the tested instrument can be compared with the temperature indicated by the built-in temperature standard. The heat medium can be oil, sand, or air. The test instruments that use air are much faster because they heat or cool faster.

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5.3.

A simple calibration setup can be assembled from a hot plate, water, and a test thermometer. The ice point of 0°C (32°F) and the boiling point 100°C (212°F) of water at standard pressure are well known and can be used to check the test thermometer. A laboratory grade thermometer is best for testing, but a dial thermometer can be used, with reduced accuracy.

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Flow Measurement and Control

EPT 05-T-03

June 1992 Draft

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Table of Contents

1. Scope 7

2. References 7

2.1. MEPS–Mobil Engineering Practices 7

2.2. Mobil Tutorials 7

2.3. API–American Petroleum Institute 7

2.4. ISA–Instrument Society of America 7

2.5. Miscellaneous 8

3. Principles of Operation 8

3.1. Differential Pressure 8

3.2. Turbine 15

3.3. Positive Displacement 17

3.4. Variable Area 20

3.5. Vortex 21

3.6. Mass 22

3.7. Magnetic 23

3.8. Ultrasonic 24

3.9. Thermal 24

3.10. Sight Flow Indication 24

3.11. Flow Switches 25

4. Device Selection 26

4.1. Orifice Meter 26

4.2. Venturi Meters 32

4.3. Pitot Tubes & Annubars 34

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4.4. Turbine....34
4.5. Positive Displacement....35
4.6. Variable Area....36
4.7. Vortex....36
4.8. Mass....36
4.9. Magnetic....37
4.10. Ultrasonic....37
4.11. Thermal....37
4.12. Dump Meters....37
4.13. Flow Transmitters....38
4.14. Flow Controllers....39
4.15. Flow Indication....39
4.16. Flow Switches....39
4.17. Flow Provers....40
4.18. Flow Totalizing....41
5. Meter Sizing....42
5.1. Orifice Plate Sizing....42
Appendix A–Example Problems - Metric Units....44
1. Gas Orifice Plate Calculation....44
2. Liquid Orifice Plate Calculations....46
Appendix B–Example Problems - Customary Units....48
1. Gas Orifice Plate Calculation....48
2. Liquid Orifice Plate Calculations....50

Table of Figures

Figure 1: Flange Taps (Preferred). (Source: p. 100, Instrument Engineers' Handbook, Bela G. Liptak, 1982 Edition, Chilton Book Company).....9

Figure 2: Pipe Taps (Discouraged). (Source: p. 126, Principles and Practices of Flow Meter Engineering, L.K. Spink, (1975) 9th Edition, Published by the Foxboro Company).....10

Figure 3: Vena Contracta or Radius Taps. (Source: p. 126, Principles and Practices of Flow Meter Engineering, L.K. Spink, (1975) 9th Edition, Published by the Foxboro Company).....11

Figure 4: Senior Orifice Fitting. (Source: Daniel Industries, Catalog 100, 1988).....12

Figure 4B: Senior Orifice Fitting. (Source: Daniel Industries, Catalog 100, 1988)....13

Figure 5: The Critical Dimensions of the Classical Venturi Tube. (Source: p. 24, Principles and Practices of Flow Meter Engineering, L.K. Spink, (1975) 9th Edition, Published by the Foxboro Company).....14

Figure 6: Pitot Tube Flow Sensor. (Source: Modification of Fig. 2.13d, p. 113, Instrument Engineers' Handbook, Bela G. Liptak, 1982 Edition, Chilton Book Company).....15

Figure 7: Turbine Meter. (Source: p. 146, Instrument Engineers' Handbook, Bela G. Liptak, 1982 Edition, Chilton Book Company).....16

Figure 8: Turbine Meter Principle of Operation. (Source: p. 146, Instrument Engineers' Handbook, Bela G. Liptak, 1982 Edition, Chilton Book Company).....17

Figure 9: Typical Positive Displacement Meters. (Source: p. 122, Instrument Engineers' Handbook, Bela G. Liptak, 1982 Edition, Chilton Book Company).....18

Figure 9B: Typical Positive Displacement Meters. (Source: p. 122, Instrument Engineers' Handbook, Bela G. Liptak, 1982 Edition, Chilton Book Company).....19

Figure 9C: Typical Positive Displacement Meters. (Source: p. 122, Instrument Engineers' Handbook, Bela G. Liptak, 1982 Edition, Chilton Book Company).....19

Figure 10: Rotameter. (Source: p. 159, Instrument Engineers' Handbook, Bela G. Liptak, 1982 Edition, Chilton Book Company).....21

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Figure 11: Vortices Generators and Detectors. (Source: p. 171, Instrument Engineers' Handbook, Bela G. Liptak, 1982 Edition, Chilton Book Company) 22

Figure 12: Magnetic Flow Meter. (Source: p. 82, Instrument Engineers' Handbook, Bela G. Liptak, 1982 Edition, Chilton Book Company) 23

Figure 13: Typical Site Flow Indicator 25

Figure 14: Swinging Vane Flow Switch. (Source: p. 69, Instrument Engineers' Handbook, Bela G. Liptak, 1982 Edition, Chilton Book Company).....26

Figure 15: Minimum Straight Length for Various Piping Configurations-Valve Upstream. (Source: AGA Report No. 3, 2nd Edition, Sept. 1985, June 1987, Reprint "Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids". Published by the American Gas Association and the American Petroleum Institute).....28

Figure 16: Minimum Straight Lengths for Various Piping Configurations-Two Ells in Different Planes. (Source: p. 16, AGA Report No. 3, 2nd Edition, Sept. 1985, June 1987, Reprint "Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids". Published by the American Gas Association and the American Petroleum Institute) 29

Figure 17: Minimum Straight Lengths for Various Piping Configurations-Two Ells in the Same Plane. (Source: p. 17, AGA Report No. 3, 2nd Edition, Sept. 1985, June 1987, Reprint "Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids". Published by the American Gas Association and the American Petroleum Institute) 30

Figure 18: Minimum Straight Length for Various Piping Configurations-Two Ells Separated by 10 Diameters of Pipe. (Source: p. 18, AGA Report No. 3, 2nd Edition, Sept. 1985, June 1987, Reprint "Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids". Published by the American Gas Association and the American Petroleum Institute).....31

Figure 19: Minimum Straight Length for Various Piping Configurations-Reducers. (Source: p. 19, AGA Report No. 3, 2nd Edition, Sept. 1985, June 1987, Reprint "Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids". Published by the American Gas Association and the American Petroleum Institute) 31

Figure 20: Upstream Straight Pipe Length for Venturi Meters. (Source: p. 166, Instrument Engineers' Handbook, Bela G. Liptak, 1982 Edition, Chilton Book Company) 33

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Figure 21: Head Loss vs. Diameter Ratio. (Source: p. 165, Instrument Engineers' Handbook, Bela G. Liptak, 1982 Edition, Chilton Book Company).....34

1. Scope

This tutorial covers equipment types, selection criteria, and operating principles regarding flow instruments that are frequently used for oil and gas production. The most commonly used types are emphasized; other types are mentioned briefly, and references are provided. Also discussed are criteria for sizing orifice meters.

2. References

The following Mobil guides and industry publications shall be considered a part of this EPT. Refer to the latest editions unless otherwise specified herein.

2.1. MEPS–Mobil Engineering Practices

MP 32-P-02	Process Measurement Instrumentation
MP 32-P-19	Instrumentation Piping and Tubing Fittings
MP 32-P-01	General Requirements for Instrumentation

2.2. Mobil Tutorials

EPT 05-T-02	Controllers and Control Theory

2.3. API–American Petroleum Institute

API MPMS 14.3.3	Manual of Petroleum Measurement Standards Chapter 14 - Natural Gas Fluids Measurement Section 3 - Concentric, Square-Edged Orifice Meters Part 3 - Natural Gas Applications Third Edition; Errata - 1994

2.4. ISA–Instrument Society of America

ISA S20	Specification Forms for Process Measurement and Control Instruments, Primary Elements and Control Valves
ISA S51.1	Process Instrumentation Terminology R(1993)

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2.5. Miscellaneous

	Spink, L.K., "Principles and Practices of Flow Meter Engineering," 9th Edition, The Foxboro Company
	Instrument Engineers' Handbook, Bela G. Liptak, 1982 Edition, Chilton Book Company

3. Principles of Operation

There are several methods of flow measurements employed in the oil and gas industry. These are discussed herein briefly. A broader discussion of each as well as some other methods is presented in Chapter 2 of the Chilton Process Measurement Handbook. Although several methods are presented here, the most common employed are orifice, turbine, positive displacement, and rotameters.

3.1. Differential Pressure

Differential pressure (also known as head type) flow measurement devices are designed to change the fluid flowing velocity or direction to create a difference in pressure between two points along a flowing stream. Common devices using this principles are orifice plates, venturi tubes, pitot tubes, and annubars.

3.1.1. Orifice Plates

1. These devices are the type most used in production and processing operations. Orifice meters are the most common form of custody transfer meter for natural gas. Numerous types of devices are available for transmission, recording, and accumulation of data from orifice meters.

2. An orifice plate is a thin plate with a precisely machined circular opening. When the plate is inserted in the flow stream and flow passes through the opening (orifice), some of the upstream pressure head is converted into velocity head. The velocity head is greatest and pressure head smallest at the "vena contracta" located slightly downstream of the orifice (see Figure 1). The differential pressure across the orifice is related to velocity by Bernoulli's equation. When the differential pressure and static pressure are measured and the orifice size, pipe size, and the gas properties are known, the flow rate can be calculated. For custody transfer applications, the industry standard is AGA Report Number 3 (API MPMS 14.3.3). The equations specified for orifice plate calculations are described in detail in Section 5 of this tutorial.

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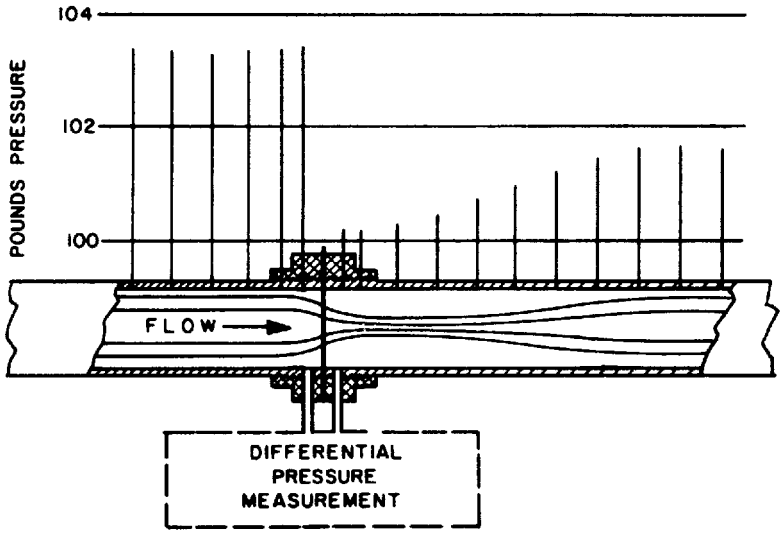

Figure 1: Flange Taps (Preferred). (Source: p. 100, Instrument Engineers' Handbook, Bela G. Liptak, 1982 Edition, Chilton Book Company)

3. At some point downstream, the velocity head returns to its original value, and the pressure returns to very nearly what it was before the orifice. The difference between the upstream pressure and the pressure at the point of recovery, which is generally considered to be eight pipe diameters downstream of the orifice, is called the permanent pressure loss. Orifice meters have a relatively high permanent pressure loss compared to other meters. The permanent pressure loss could be as high as 90 percent of the maximum pressure differential. In most installations, this will be less than 35 kPa (5 psi).

4. Several factors affect orifice meter accuracy. Some factors are based on the accuracy of measuring the differential pressure. Other factors are based on how accurately the flow rate is related to the differential pressure.

5. Upstream disturbances, flow turbulence, and pipe roughness influence the relationship of flow to differential pressure. Accuracy is improved by honing welding burrs and maintaining a high Reynolds number. Overall accuracy of ± 2 to 5 percent is common, but it can be improved to about 1 percent when all sources of inaccuracy are minimized.

6. Orifice meters are limited in practical rangeability to about 3 to 1 because the differential pressure output is proportional to the square of the flow. The graduations on the readout device get too close to each other for accurate reading below about one third of the flow range (except where a computerized readout is employed). The differential pressure shall normally be between 50 percent and 70 percent of the full scale reading at normal design flowrate.

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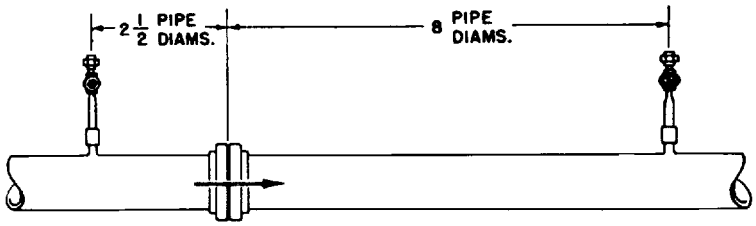
7. Accurate measurements require flow without large swirls. Therefore, there are requirements for straight runs of piping upstream and downstream of the orifice; straightening vanes are sometimes used.

8. The simplest method of mounting an orifice plate is to insert it between two flanges. Ordinary piping flanges can be used, but orifice flanges allow easy centering of the orifice plate. It is most common to purchase special flanges properly bored and tapped for the connection of differential pressure sensing instruments. This type of installation is commonly known as "flange tap" installation.

9. Measurement is not as accurate when pressure sensing taps are installed in the piping, since the pressure differential is not as great at these locations as at flange taps for a given situation. This type of installation is known as full flow taps or, more commonly, "pipe taps." It is not normally used and shall be discouraged. Figure 2 shows full flow pipe taps.



Full-flow Taps at $2\frac{1}{2}$ and 8 Pipe Diameters

Figure 2: Pipe Taps (Discouraged). (Source: p. 126, Principles and Practices of Flow Meter Engineering, L.K. Spink, (1975) 9th Edition, Published by the Foxboro Company)

10. Another form of pipe taps is vena contracta taps, shown in Figure 3. In this type, one tap is located upstream about one pipe diameter and the other is located downstream at the point of minimum pressure. The location of the downstream tap is critical and depends on the orifice size. For beta ratios up to 0.72, placing the downstream pressure tap $^1/_2$ pipe diameter from the orifice provides a good approximation to vena contracta taps. Vena contracta taps are rarely used on production facilities.

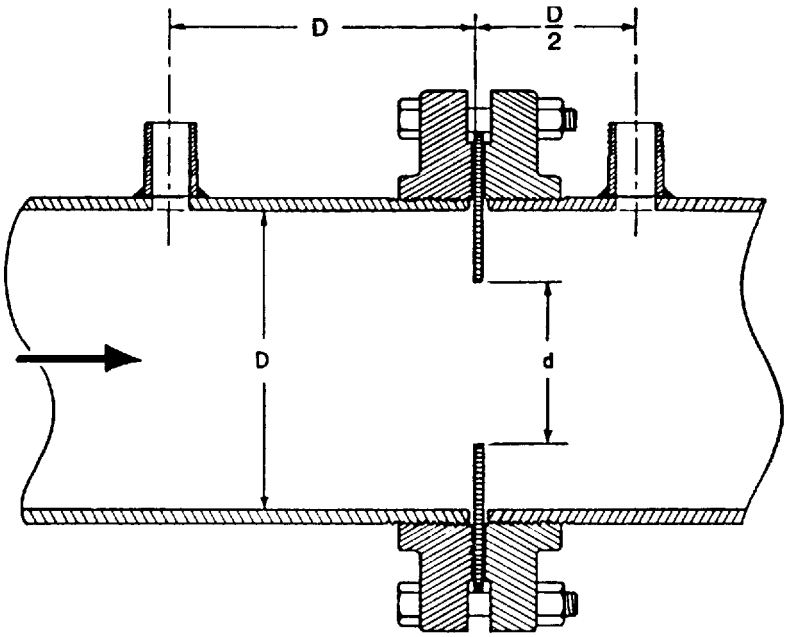


Figure 3: Vena Contracta or Radius Taps. (Source: p. 126, Principles and Practices of Flow Meter Engineering, L.K. Spink, (1975) 9th Edition, Published by the Foxboro Company)

11. Flanged orifice meters require the line to be depressured and the flanges unbolted and spread, in order to change or inspect the orifice plate. Manufactured orifice flanges are equipped with a "jacking" screw to spread the flanges for plate removal.

12. Quick change fittings are available to use in installations that require periodic orifice plate service or changing. These fittings are manufactured by several companies but are usually called by the trade names "Junior" and "Senior" even if they are not purchased from the company that holds those trademarks. The "Junior" fitting allows the orifice plate to be changed without jacking the fittings apart, but it does require that the meter tube be depressured. The "Senior" fitting allows the plate to be changed without depressuring. Figure 4 shows a "Senior" fitting. Manufacturers' instructions for changing orifice plates shall be followed carefully to avoid danger to personnel.

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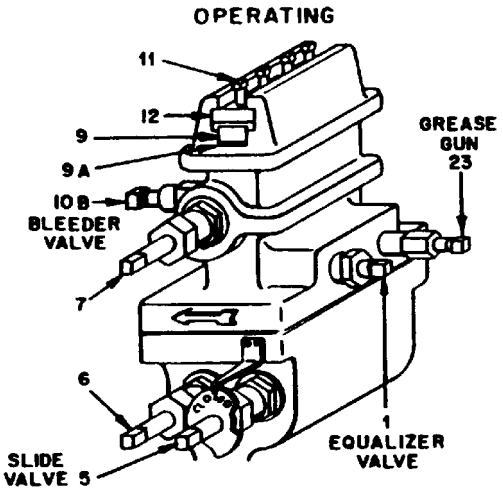

TO REMOVE ORIFICE PLATE

(A) OPEN NO. 1 (MAX. TWO TURNS ONLY)
(B) OPEN NO. 5
(C) ROTATE NO. 6
(D) ROTATE NO. 7
(E) CLOSE NO. 5
(F) CLOSE NO. 1
(G) OPEN NO. 10B
(H) LUBRICATE THRU NO. 23
(I) LOOSEN NO. 11 (DO NOT REMOVE NO. 12)
(J) ROTATE NO. 7 TO FREE NOS. 9 AND 9A
(K) REMOVE NOS. 12, 9 AND 9A

TO REPLACE ORIFICE PLATE

(A) CLOSE 10B
(B) ROTATE NO. 7 SLOWLY UNTIL PLATE CARRIER IS CLEAR OF SEALING BAR AND GASKET LEVEL. DO NOT LOWER PLATE CARRIER ONTO SLIDE VALVE.
(C) REPLACE NOS. 9A, 9 AND 12
(D) TIGHTEN NO. 11
(E) OPEN NO. 1
(F) OPEN NO. 5
(G) ROTATE NO. 7
(H) ROTATE NO. 6
(I) CLOSE NO. 5
(J) CLOSE NO. 1
(K) OPEN 10B
(L) LUBRICATE THRU NO. 23
(B) CLOSE NO. 10B

Figure 4: Senior Orifice Fitting. (Source: Daniel Industries, Catalog 100, 1988)

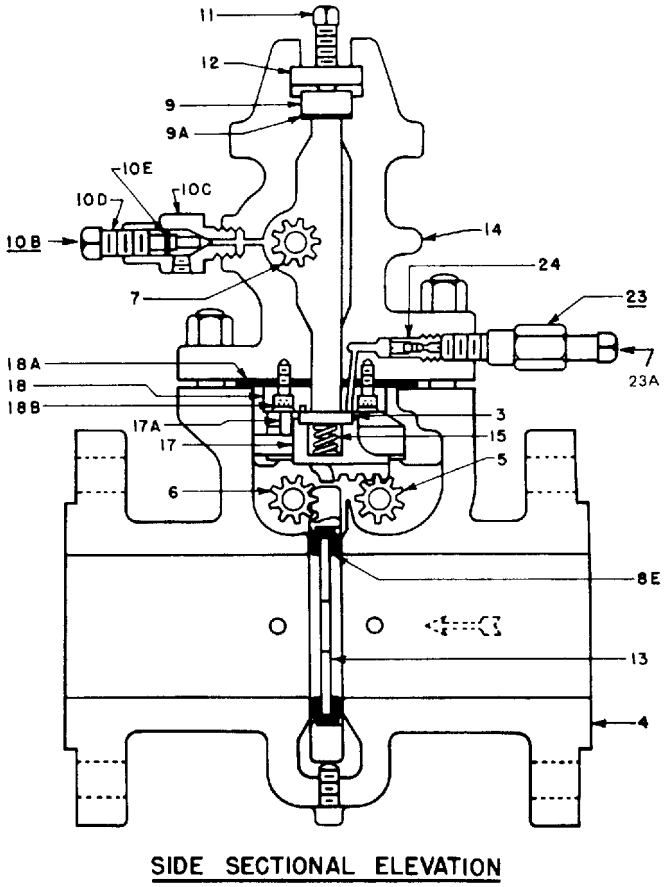

Figure 4B: Senior Orifice Fitting. (Source: Daniel Industries, Catalog 100, 1988)

13. Orifice plates can be manufactured of any metal that is compatible with the measured fluid. Type 316 stainless steel is used for most hydrocarbon service. Orifice flanges and quick change fittings are usually made from carbon steel.

14. The most common shape for orifice plates for gas measurement is circular, with an orifice that is round and located in the center of the plate. The ISA standard orifice has a sharp edged straight bore.

15. Eccentric orifice plates have the hole placed with its edge tangential with either the top or the bottom of the pipe. This type of orifice is sometimes used for measurement when either liquids or gases are expected to be entrained in the process fluid. The hole will be at the top when gases are present and at the bottom when liquids are present.

16. It is also possible in liquid service to use a segmental orifice for the same purpose as the eccentric orifice. In a segmental orifice, the opening is semicircular.

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17. Special edges milled on the orifice hole can improve performance at low Reynolds numbers of flow in the pipe. Several different shapes have been tried and are somewhat effective, but more common practice is to reduce the pipe size to increase the Reynolds number to a value above 10,000.

18. A detailed discussion is presented in section 2.12 of the Chilton Process Measurement Handbook.

3.1.2. Venturi Tubes

1. The Venturi Tube, also known as a low-loss flow tube, works by the same principles as an orifice plate. The venturi tube has a gradual reduction in diameter to its narrowest point, the vena contracta, and then a gradual expansion back to the original pipe diameter. This device is more expensive to manufacture than an orifice plate, but it has a much lower permanent pressure loss. The internal path of the venturi meter is machine-finished and specifically contoured to minimize this pressure loss. Permanent losses on the order of 5 percent of the measured pressure differential are obtainable. A typical Venturi meter is illustrated in Figure 5.

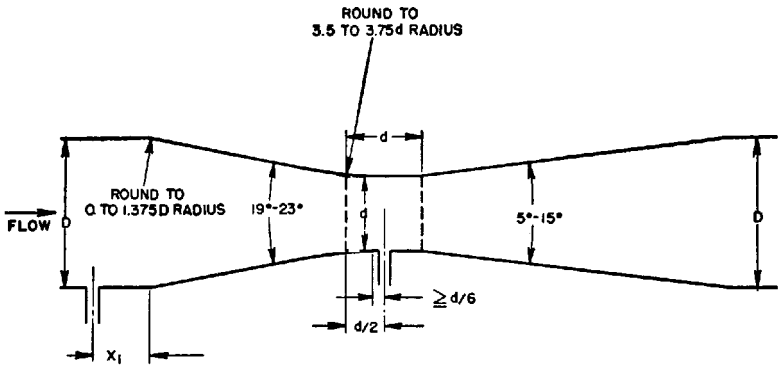

Figure 5: The Critical Dimensions of the Classical Venturi Tube. (Source: p. 24, Principles and Practices of Flow Meter Engineering, L.K. Spink, (1975) 9th Edition, Published by the Foxboro Company)

2. A detailed discussion is presented in section 2.23 of the Chilton Process Measurement Handbook.

3.1.3. Pitot Tubes and Annubars

1. The basic tube, as shown in Figure 6, has two concentric tubes. The end of the center tube is open and pointed into the flow. The other tube is closed at the end but has holes in the side that are perpendicular to the flow, to sense static pressure. The flow is calculated from the difference between the ram pressure in the center tube and the static pressure in the outer tube.

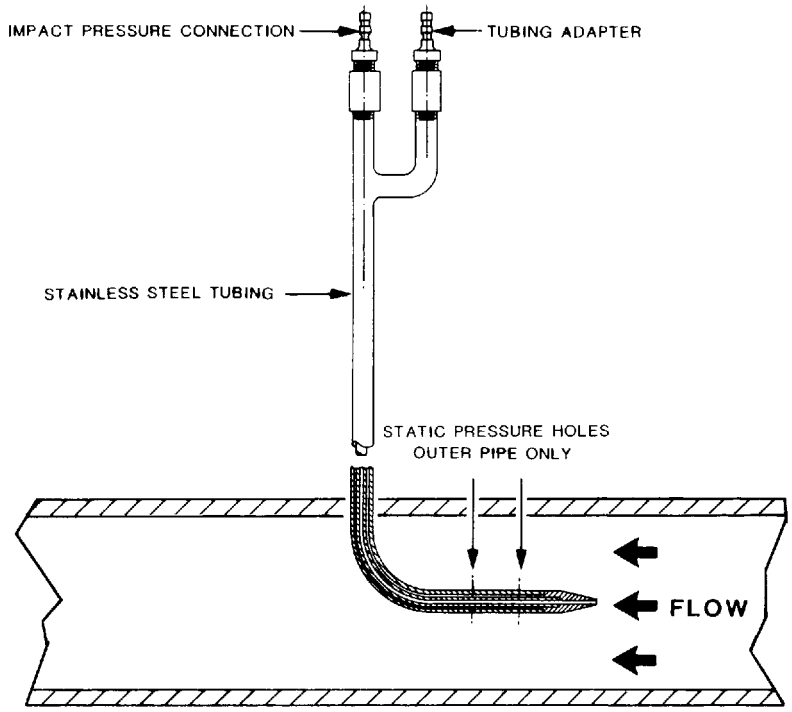

Figure 6: Pitot Tube Flow Sensor. (Source: Modification of Fig. 2.13d, p. 113, Instrument Engineers' Handbook, Bela G. Liptak, 1982 Edition, Chilton Book Company)

2. An annubar is a more accurate device based on the pitot tube concept. It employs several velocity sensing openings subjected to the fluid flow. The resulting ram and static pressures are averaged to obtain an accurate indication of the flow rate.

3. A detailed discussion of both pitot tubes and annubars is presented in section 2.13 of the Chilton Process Measurement Handbook.

3.2. Turbine

1. Turbine meters (Figure 7) consist of a propeller mounted in a precisely machined housing. One or two pickup devices are mounted externally in the body in the same plane as the rotor blades. Fluid flowing through the meter causes the rotor to rotate at a speed proportional to the flow velocity. As each blade tip passes the pickup, a single pulse is generated (See Figure 8). The number of pulses per unit time allows calculation of the flow velocity, which can be used to determine flow rate.

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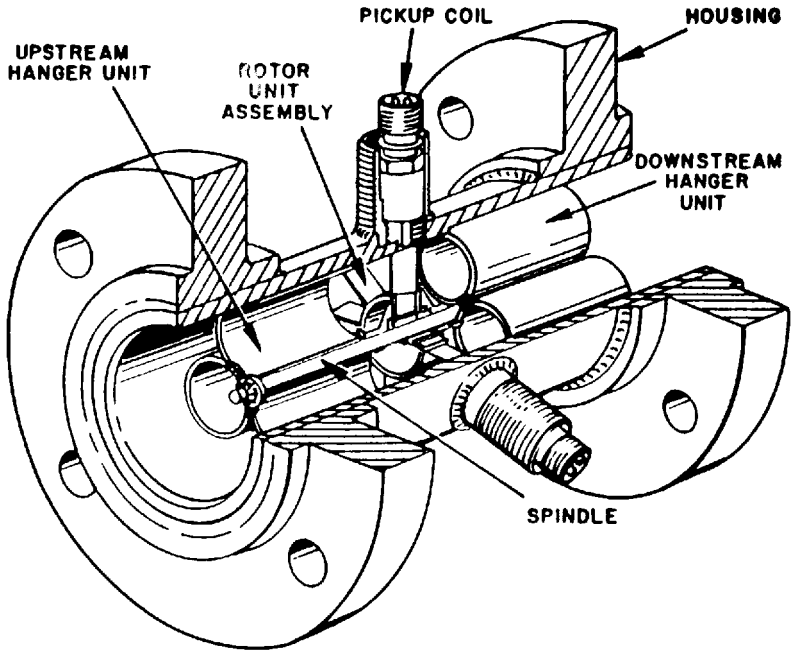


Figure 7: Turbine Meter. (Source: p. 146, Instrument Engineers' Handbook, Bela G. Liptak, 1982 Edition, Chilton Book Company)

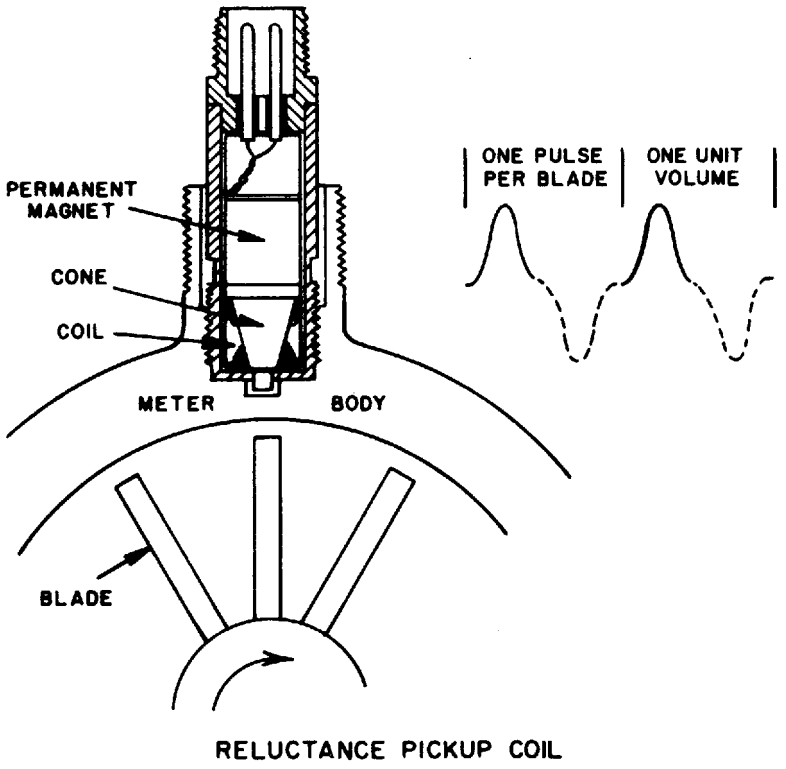


Figure 8: Turbine Meter Principle of Operation. (Source: p. 146, Instrument Engineers' Handbook, Bela G. Liptak, 1982 Edition, Chilton Book Company)

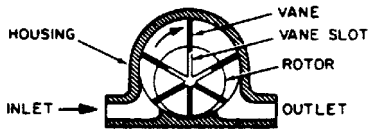
2. Most turbine meters are threaded or mounted between flanges. Some turbine meters that insert into user supplied piping are available.

3. Refer to section 2.20 of the Chilton Process Measurement Handbook for a more detailed discussion.

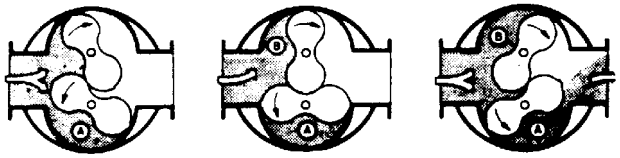
3.3. Positive Displacement

3.3.1.

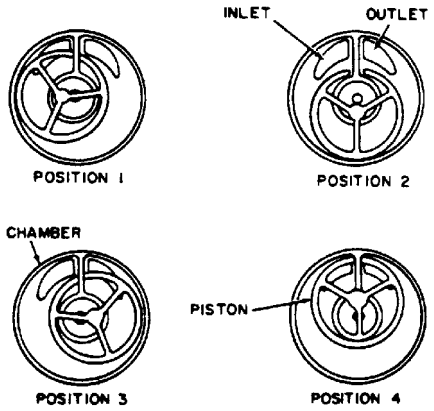
Positive displacement meters are mechanical devices that split the flow into incremental volumes and then count the number of these volumes that pass. Several techniques have been developed for positive displacement flow measurement. Figure 9 shows several of these techniques. Almost all positive displacement meters used in common production facility liquid metering are rotating vane types.



Rotating vane meter

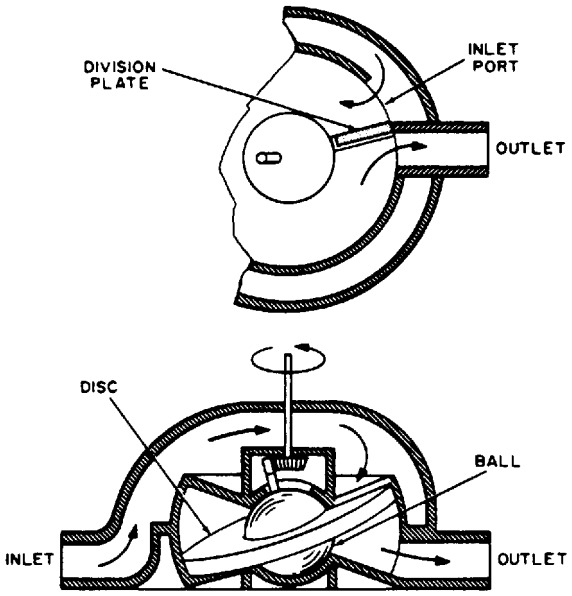


Rotating lobe meter



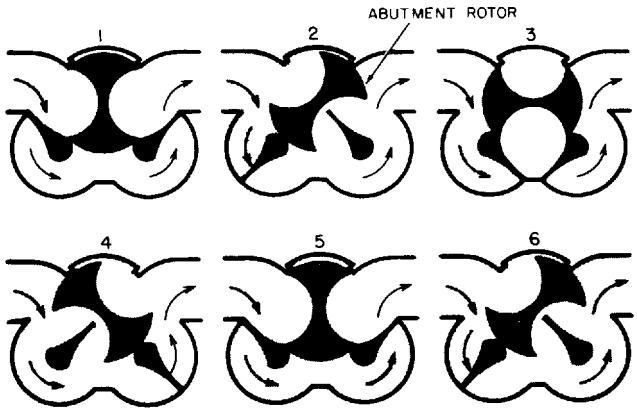
Oscillating piston meter

Figure 9: Typical Positive Displacement Meters. (Source: p. 122, Instrument Engineers' Handbook, Bela G. Liptak, 1982 Edition, Chilton Book Company)



Nutating disk meter

Figure 9B: Typical Positive Displacement Meters. (Source: p. 122, Instrument Engineers' Handbook, Bela G. Liptak, 1982 Edition, Chilton Book Company)



Six phase metering cycle of
rotary displacement-type flowmeter

Figure 9C: Typical Positive Displacement Meters. (Source: p. 122, Instrument Engineers' Handbook, Bela G. Liptak, 1982 Edition, Chilton Book Company)

3.3.2.

The most accepted method of custody transfer of crude oil is by positive displacement meters. Accuracy on the order of ± 0.25 percent is usually attainable, and accuracy as good as ± 0.1 percent can be achieved with proper

installation and calibration. Positive displacement meters are used for custody transfer of low pressure gas in commercial and residential service but are not usually used for gas measurement in production facilities.

3.3.3.

Positive displacement meters have many closely machined parts, making them more expensive than other flow metering instrument and producing higher maintenance costs. Wear of the machined surfaces causes accuracy loss; thus, care shall be taken to prevent abrasives from passing through the meters.

3.3.4.

Some manufacturers make positive displacement meters for use where abrasives are present. However, these meters are not as accurate as positive displacement meters used for custody transfer.

3.3.5.

Refer to sections 2.14 and 2.15 of the Chilton Process Measurement Handbook for more details.

3.4. Variable Area

3.4.1.

Variable area meters, which are also known as "rotameters," have a vertical tapered tube that is partially blocked by a piece of material called a "float." The float is not actually buoyant in the process fluid and is constructed from a heavy material, often stainless steel. When fluid enters the bottom of the rotameter, it exerts pressure on the float and causes the float to rise in the tube. As the float rises, the space around the float in the tube increases and allows the pressure above and below the float to equalize. When the difference in pressure is such that the weight of the float is counterbalanced, the float becomes stationary and the flow can be determined. The float height is proportional to the flow rate.

3.4.2.

The tube can be transparent to allow observation of the float if the pressure is low enough for safety. If the pressure is high enough to cause safety concerns or the fluid is considered too dangerous for other reasons, the tube can be made of stainless steel and the position of the float sensed magnetically. This type is known as an armored rotameter. Figure 10 shows a typical rotameter.

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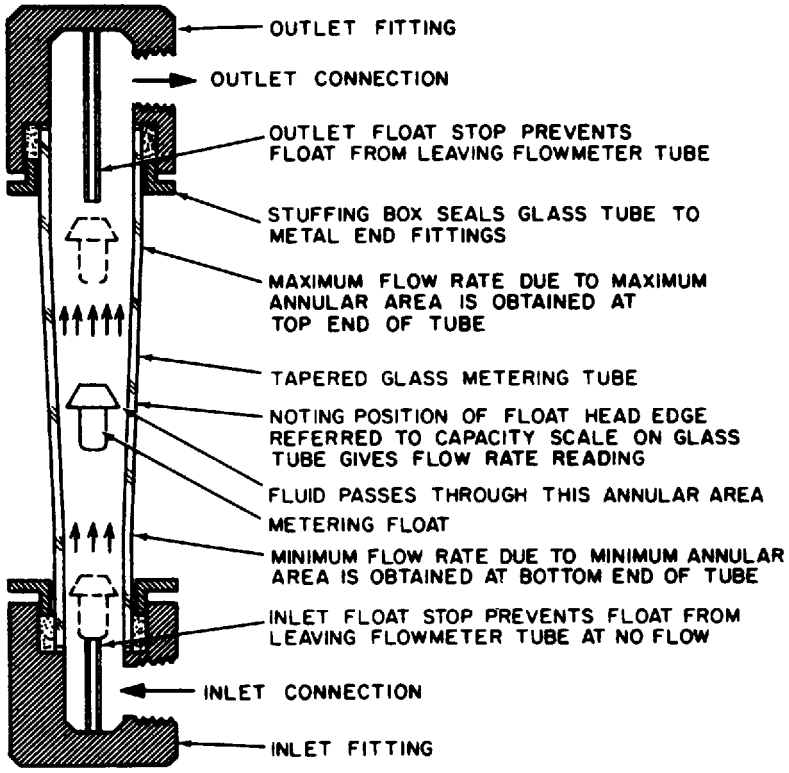
OUTLET FITTING
OUTLET CONNECTION
OUTLET FLOAT STOP PREVENTS FLOAT FROM LEAVING FLOWMETER TUBE
STUFFING BOX SEALS GLASS TUBE TO METAL END FITTINGS
MAXIMUM FLOW RATE DUE TO MAXIMUM ANNULAR AREA IS OBTAINED AT TOP END OF TUBE
TAPERED GLASS METERING TUBE
NOTING POSITION OF FLOAT HEAD EDGE REFERRED TO CAPACITY SCALE ON GLASS TUBE GIVES FLOW RATE READING
FLUID PASSES THROUGH THIS ANNULAR AREA
METERING FLOAT
MINIMUM FLOW RATE DUE TO MINIMUM ANNULAR AREA IS OBTAINED AT BOTTOM END OF TUBE
INLET FLOAT STOP PREVENTS FLOAT FROM LEAVING FLOWMETER TUBE AT NO FLOW
INLET CONNECTION
INLET FITTING

Figure 10: Rotameter. (Source: p. 159, Instrument Engineers' Handbook, Bela G. Liptak, 1982 Edition, Chilton Book Company)

3.4.3.

More details are presented in section 2.22 of the Chilton Process Measurement Handbook.

3.5. Vortex

3.5.1.

Vortex meters use a non-streamlined body inserted into the flow to generate turbulence. Vortices or eddies leave a body at a rate proportional to the flow rate. These vortices can be detected by several methods and the flow rate calculated. Figure 11 illustrates several methods used to generate and detect vortices.

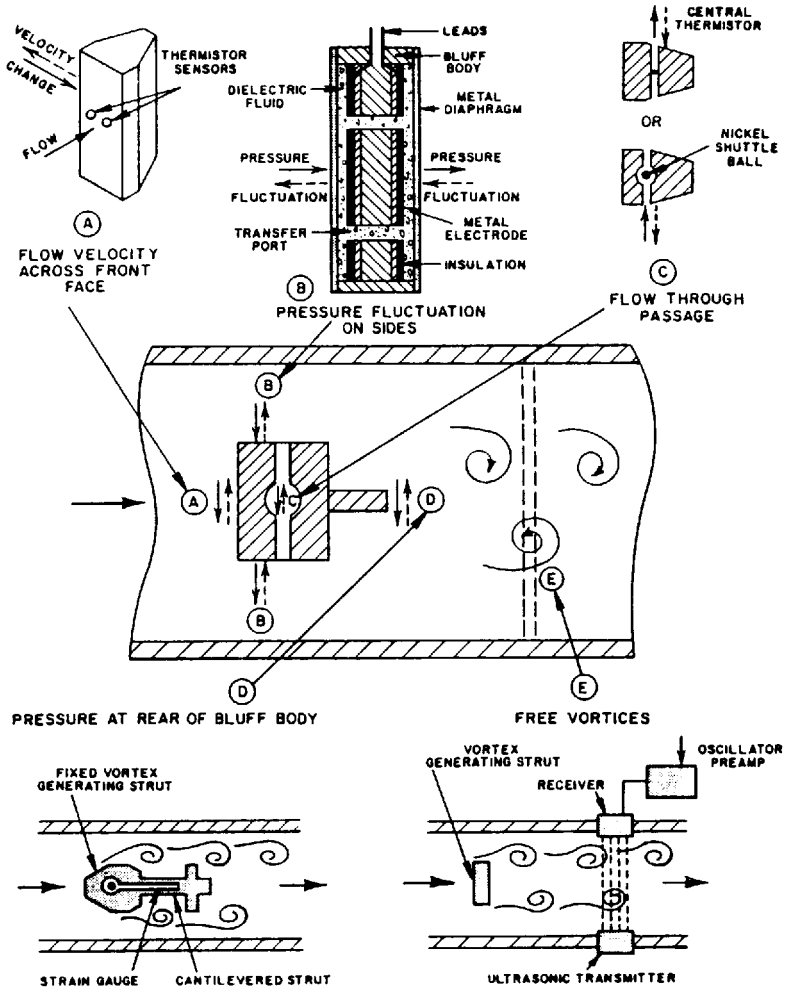

Figure 11: Vortices Generators and Detectors. (Source: p. 171, Instrument Engineers' Handbook, Bela G. Liptak, 1982 Edition, Chilton Book Company)

3.5.2.

A detailed discussion is presented in section 2.24 of the Chilton Process Measurement Handbook.

3.6. Mass

Mass flow meters, as the name implies, measure the mass flow directly. In general, these meters are based on Newton's second law of angular motion. That is, mass flow is proportional to the angular force (torque) or pressure exerted on a body by the flowing fluid. Refer to section 2.10 of the Chilton Process Measurement Handbook for a detailed discussion.

3.7. Magnetic

3.7.1.

Magnetic flow meters operate in accordance with Faraday's Law, which states that a conductor passing through a magnetic field will produce a voltage that depends on the conductor's velocity. If a conducting liquid passes through a magnetic field, the path between two electrodes acts as a conductor, thus inducing a voltage between the electrodes. Figure 12 shows a magnetic flow meter.

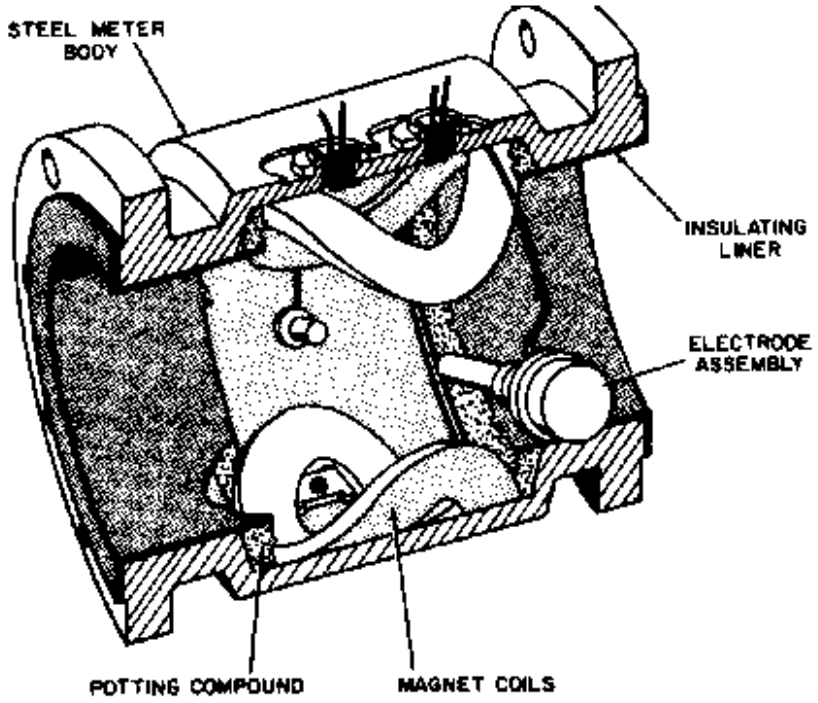

Figure 12: Magnetic Flow Meter. (Source: p. 82, Instrument Engineers' Handbook, Bela G. Liptak, 1982 Edition, Chilton Book Company)

3.7.2.

Magnetic flow meters can be used to measure the flow of most conducting liquids. The primary advantages of magnetic meters are that they have no obstructions in the pipe and no holes to clog. The pressure loss is no greater than for an equivalent length of pipe, and solids present little problem. Magnetic flow meters are not used in the oil and gas industry because hydrocarbons are nonconductive.

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3.7.3.

Refer to section 2.9 of the Chilton Process Measurement Handbook for more details.

3.8. Ultrasonic

Ultrasonic flow meters measure flow by timing an ultrasonic signal's passage through a flowing fluid. Several techniques (across flow, against flow, with flow, etc.) are used with varying degrees of accuracy. Some specific techniques are discussed in section 2.21 of the Chilton Process Measurement Handbook. The systems are seldom used, and, when they are used, they are used for indication only.

3.9. Thermal

Thermal flow meters use a form of mass flow measurement based on the principles of heat transfer. There are two basic types. In one type, the change in temperature of the fluid is measured based on a known heat input; the other type is based on the effect on a heated sensor of the flowing stream. Both of these concepts are discussed in detail in section 2.19 of the Chilton Process Measurement Handbook. These units have limited use in protection and processing facilities.

3.10. Sight Flow Indication

3.10.1.

A sight flow indicator is basically a device that provides a window into the process line for visual observation of fluid flow. Various techniques are used to enhance the visibility of the fluid, e.g., flappers, turbine blades, etc. A typical sight flow indicator with turbine blades is shown in Figure 13.

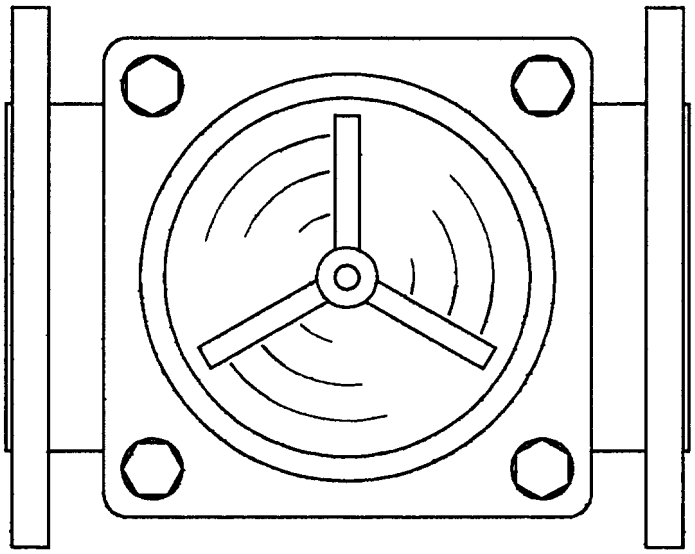

Figure 13: Typical Site Flow Indicator

3.10.2.

Refer to section 2.16 of the Chilton Process Measurement Handbook for a more detailed discussion.

3.11. Flow Switches

Flow switches employ techniques similar to those used by site flow indicators to detect whether or not flow exists above or below some set point. A typical flow switch is shown in Figure 14. Details of the basic device are presented in section 2.6 of the Chilton Process Measurement Handbook.

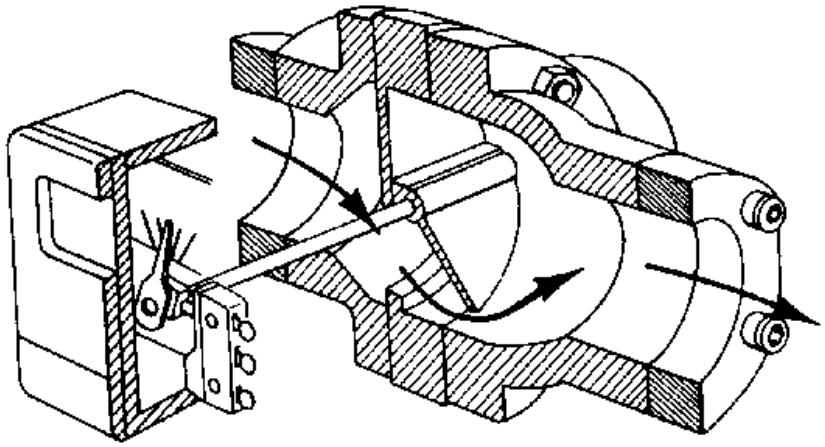

Figure 14: Swinging Vane Flow Switch. (Source: p. 69, Instrument Engineers' Handbook, Bela G. Liptak, 1982 Edition, Chilton Book Company)

4. Device Selection

4.1. Orifice Meter

4.1.1.

These devices, sometimes referred to as differential pressure or head meters, constitute the most common type of flow meter used in production and processing operations. The orifice meter is the common means of measurement used in custody transfer of natural gas.

4.1.2.

Orifice meters are occasionally used for liquids when a turndown ratio of three to one is satisfactory and the liquid's viscosity is low. An indication that the liquid viscosity may be too high is that the correction factor gets large or goes off the chart. The viscosity correction factor shall be taken into consideration for viscosities above 0.005 Pa s (5 cp). The Reynolds number shall be 10,000 or more to ensure fully turbulent flow.

4.1.3.

Turndown ratios of over three to one can be accommodated by using multiple orifices in a quick change fitting if the flow rate changes in a manner that allows time to change the orifice.

4.1.4.

Orifice meters require straight runs of pipe upstream and downstream. This can become a limiting factor when space is a consideration. The following figures are from the AGA Report No. 3, which shows the required minimum straight lengths for various piping configurations:

1. Figure 15 - Valve upstream.
2. Figure 16 - Two ells in different planes.
3. Figure 17 - Two ells in the same plane.
4. Figure 18 - Two ells separated by 10 diameters of pipe.
5. Figure 19 - Reducers

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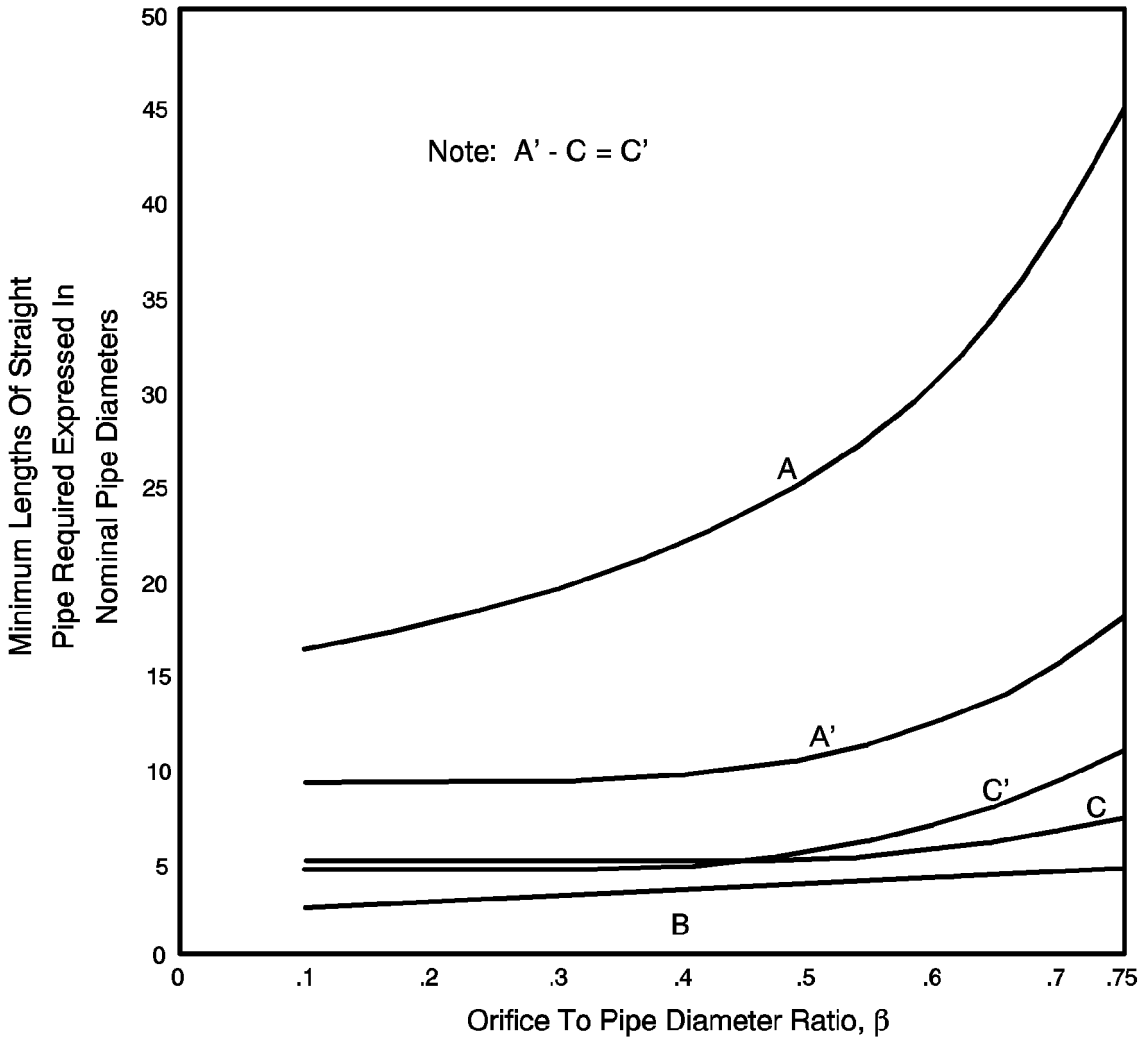

Figure 15: Minimum Straight Length for Various Piping Configurations-Valve Upstream. (Source: AGA Report No. 3, 2nd Edition, Sept. 1985, June 1987, Reprint "Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids". Published by the American Gas Association and the American Petroleum Institute)

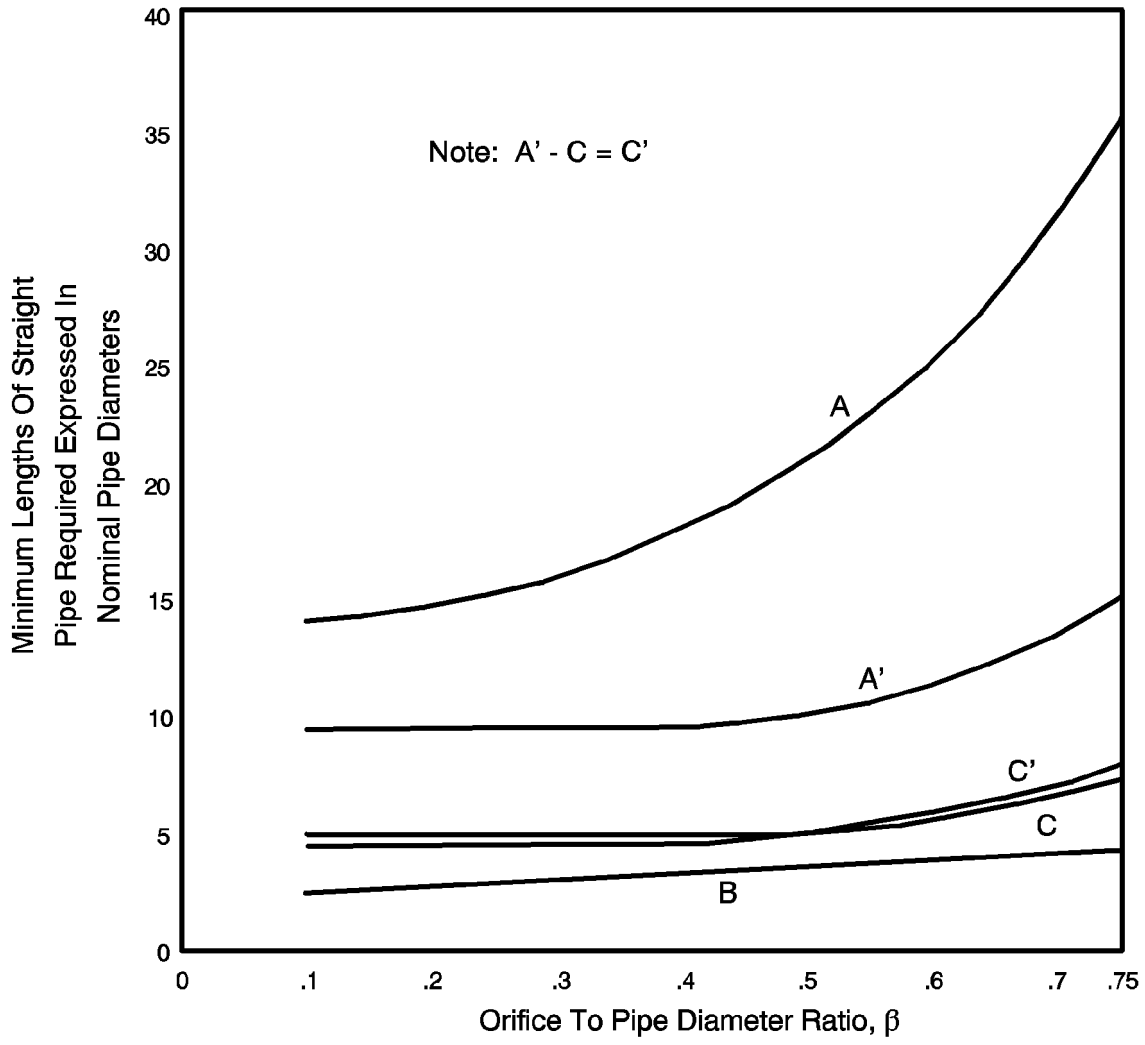

Figure 16: Minimum Straight Lengths for Various Piping Configurations-Two Ells in Different Planes. (Source: p. 16, AGA Report No. 3, 2nd Edition, Sept. 1985, June 1987, Reprint "Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids". Published by the American Gas Association and the American Petroleum Institute)

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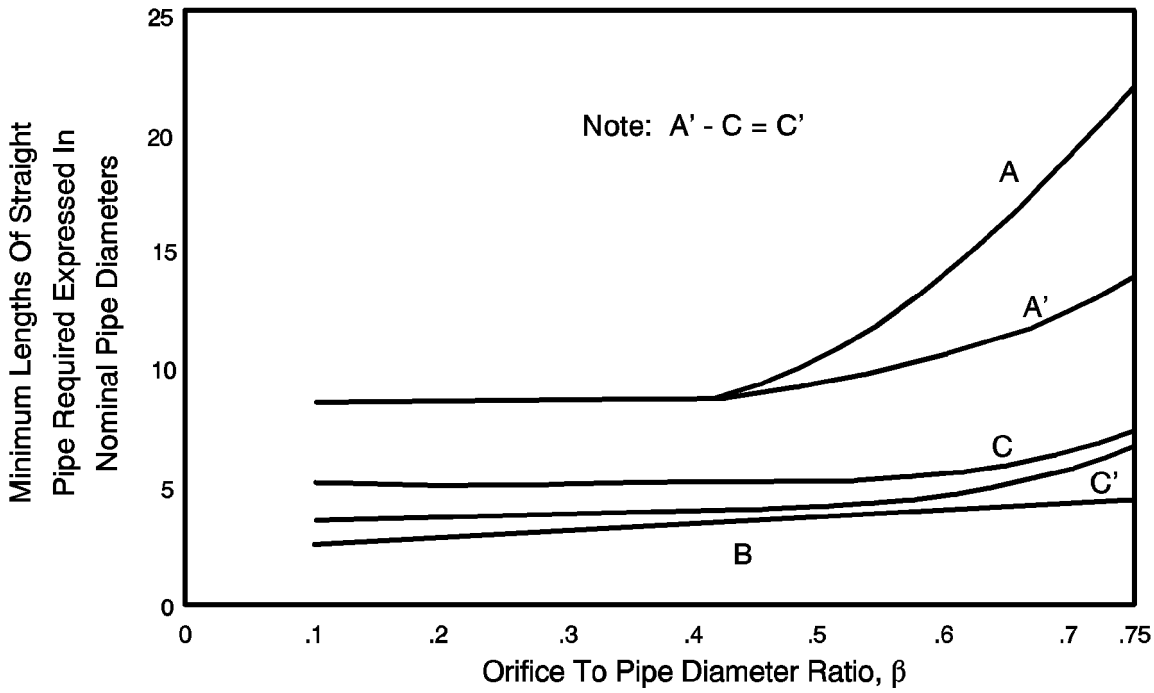

Figure 17: Minimum Straight Lengths for Various Piping Configurations-Two Ells in the Same Plane. (Source: p. 17, AGA Report No. 3, 2nd Edition, Sept. 1985, June 1987, Reprint "Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids". Published by the American Gas Association and the American Petroleum Institute)

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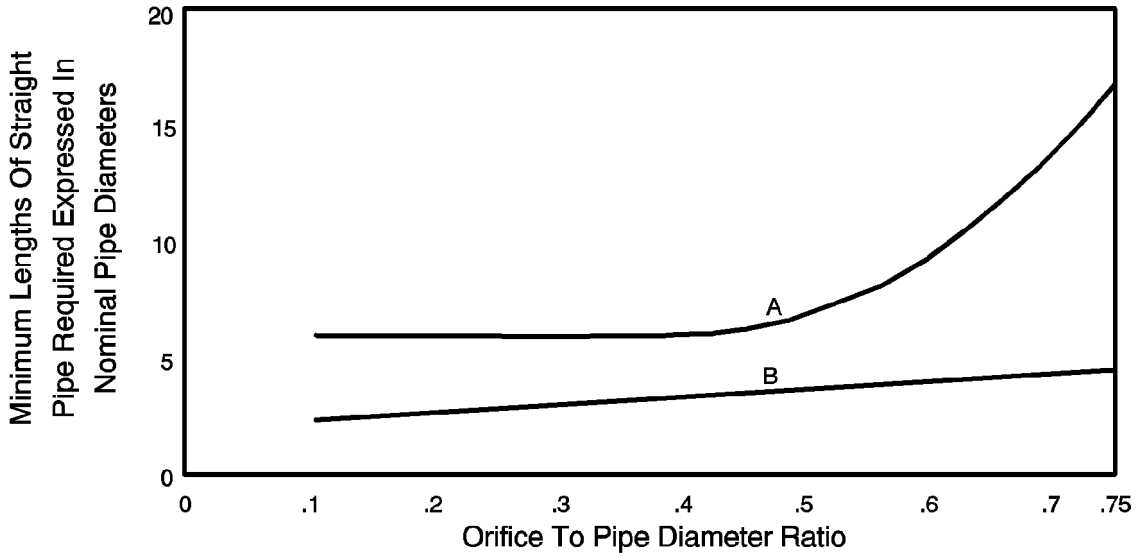

Figure 18: Minimum Straight Length for Various Piping Configurations-Two Ells Separated by 10 Diameters of Pipe. (Source: p. 18, AGA Report No. 3, 2nd Edition, Sept. 1985, June 1987, Reprint "Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids". Published by the American Gas Association and the American Petroleum Institute)

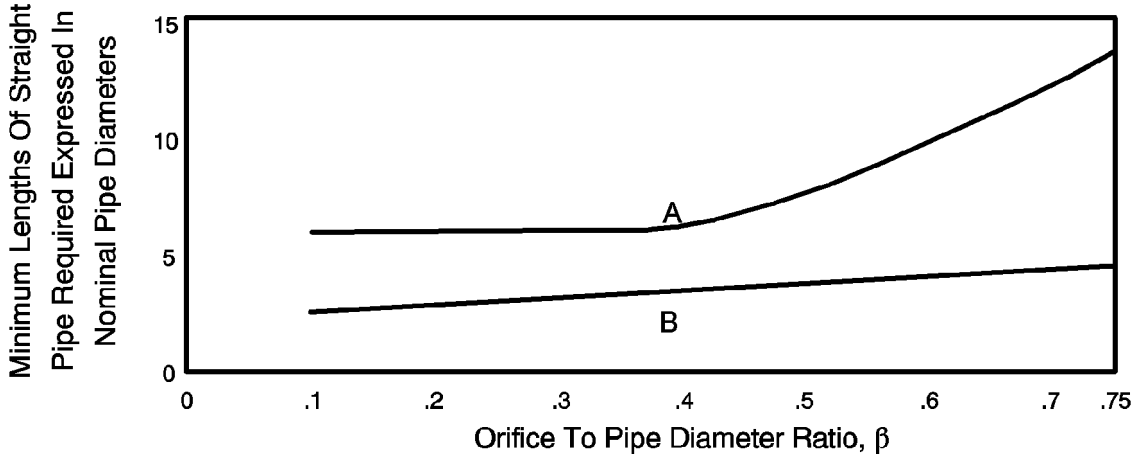

Figure 19: Minimum Straight Length for Various Piping Configurations-Reducers. (Source: p. 19, AGA Report No. 3, 2nd Edition, Sept. 1985, June 1987, Reprint "Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids". Published by the American Gas Association and the American Petroleum Institute)

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4.1.5.

Where adequate meter run space is not available, straightening vanes shall be considered for allocation meter installations. For other applications (e.g., flow control, indication, etc.), deviations from the required lengths to fit physical constraints are acceptable. A minimum allowable upstream length of four pipe diameters and downstream length of two pipe diameters shall be provided.

4.1.6.

The design orifice differential pressure shall be 25 kPa (100 in of water column). However, designs of 12.4 to 75 kPa (50 to 300 in) are sometimes used in control applications. For gas meters, erroneous readings will be obtained if a liquid buildup occurs in one of the process connections. For liquid meters, erroneous readings will be obtained if a vapor buildup occurs in one of the process connections. The usual method to prevent this error is to slope the process connections downward from the meter for liquid runs and upward for gas runs. If this is not practical, small vessels (called seal pots) can be installed to drain liquid buildup in gas runs and vent gas buildup in liquid runs.

4.1.7.

Orifice meter runs used for custody transfer shall be factory assembled and calibrated for the greatest possible accuracy.

4.1.8.

The cost of orifice meters can vary from $800 (U.S.) to over $4000, depending on requirements.

4.2. Venturi Meters

4.2.1.

A venturi or low loss flow tube is a good substitute for an orifice plate installation if the permanent pressure loss of an orifice plate is not acceptable or if there is not adequate room for proper orifice meter installation. Venturi meters provide accuracy within about 1 percent and 3 to 1 rangeability.

4.2.2.

The required straight pipe run upstream of the venturi meter is less than that required by an orifice. Figure 20 shows the upstream pipe requirement. There is no requirement for the downstream straight piping run. Figure 21 shows permanent pressure loss curves.

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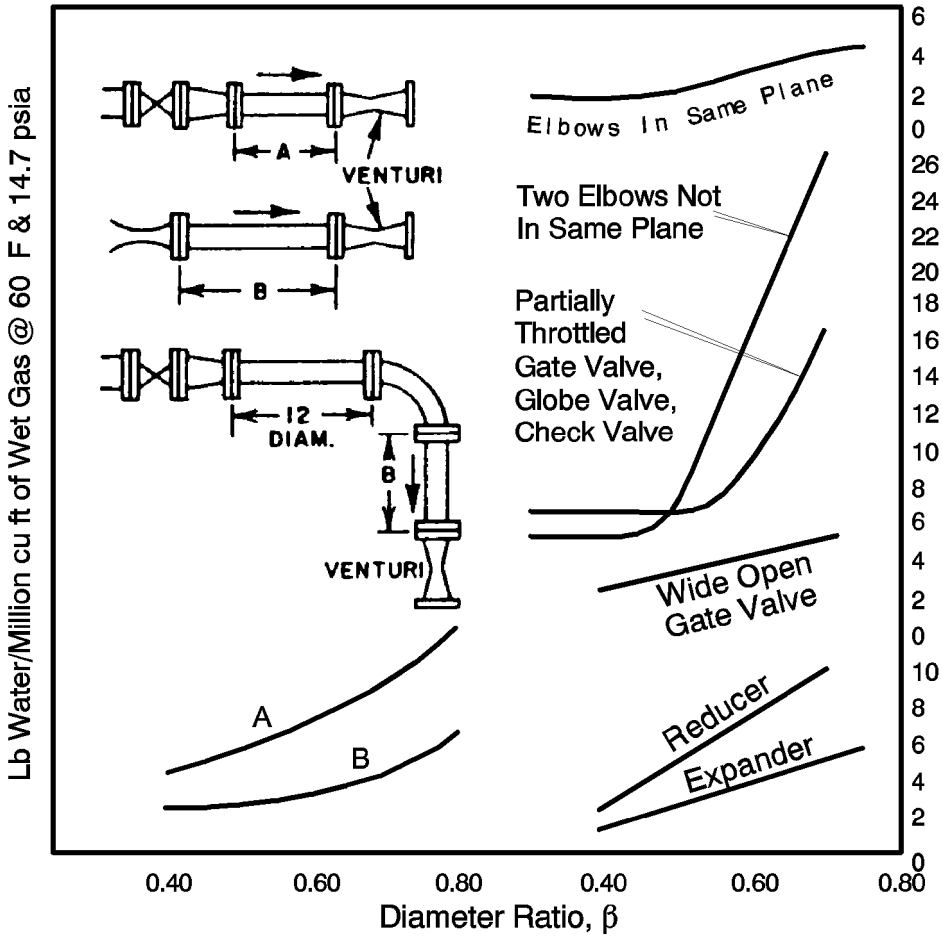

Figure 20: Upstream Straight Pipe Length for Venturi Meters. (Source: p. 166, Instrument Engineers' Handbook, Bela G. Liptak, 1982 Edition, Chilton Book Company)

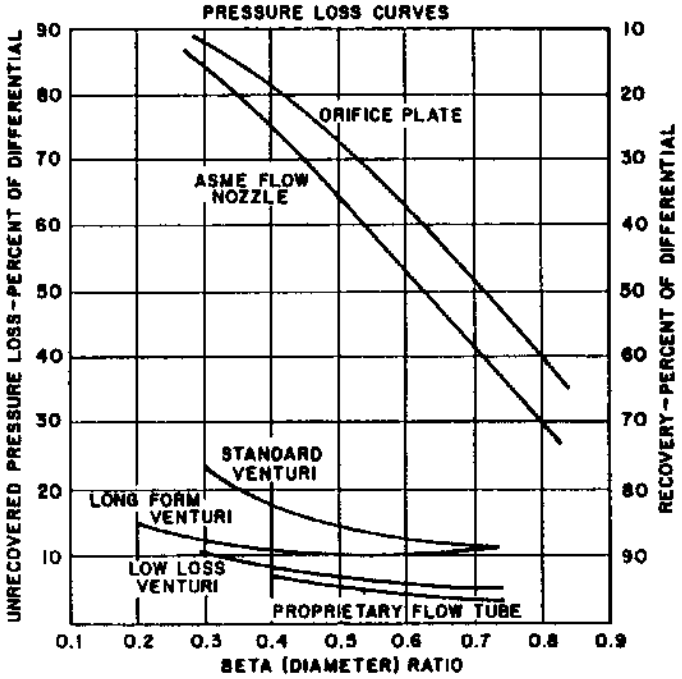

Figure 21: Head Loss vs. Diameter Ratio. (Source: p. 165, Instrument Engineers' Handbook, Bela G. Liptak, 1982 Edition, Chilton Book Company)

4.3. Pitot Tubes & Annubars

Pitot tube and annubars are a low cost approach to metering. A common application is in services where a line pressure drop is unacceptable. These devices are well united for compressor suction line and system vent line flow indication. Unit costs vary from $500 to $1000 (U.S.).

4.4. Turbine

4.4.1.

Very accurate measurement of flow for low viscosity liquids is possible with turbine meters. These meters are quite suitable for custody transfer applications. Accuracy varies but is usually on the order of 0.25 percent for liquids. The turndown ratio for turbine meters is at least 10 to 1, with some manufacturers claiming much greater ratios.

4.4.2.

Turbine meters are slightly more expensive than orifice meters and require more maintenance but are simpler to read than orifice meters. Liquid slugs in

a gas turbine meter can exert large forces on the bearings and cause damage. Metering accuracy is severely affected by the presence of liquid slugs even if mechanical damage does not occur.

4.4.3.

Like orifice meters, turbine meters require a straight run of pipe upstream for accurate measurement. Typically, 10 pipe diameters upstream and five diameters downstream are required for accurate flow measurement.

4.4.4.

Viscosities above 0.02 Pa s (20 cp) are not easily handled by turbine meters. For higher viscosity liquids, either select a positive displacement meter or consult the manufacturer for guidance.

4.5. Positive Displacement

4.5.1.

Positive displacement meters are usually the best choice for flow measurement of liquids with viscosities above 0.02 Pa s (20 cp). Viscosities below 0.02 Pa s (20 cp) cause rapid decreases in rangeability, so a turbine meter is usually a better choice for such liquids.

4.5.2.

Standard positive displacement meters can be used for fluid viscosities as high as 0.4 Pa s (400 cp), and special models can be used up to around 2 Pa s (2000 cp). The manufacturer's literature gives limits specific to the particular model under consideration. Accuracy from 0.5 to 1 percent is common, with rangeability of 20 to 1.

4.5.3.

Positive displacement meters do not require a straight meter run. An air eliminator and a strainer are often used upstream of the meter to eliminate gas bubbles and abrasive particles, which can cause damage and/or inaccuracy.

4.5.4.

A positive displacement meter designated for severe service shall be chosen for test separator measurements. This service often has sand and other abrasives entrained in the liquid and can cause meter damage. Well test measurements normally need not be as accurate as custody transfer measurements. Severe service meters are manufactured with large clearances and easily changed internals for this type of service.

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4.6. Variable Area

4.6.1.

Variable area meters (or rotameters) are simple and inexpensive and are widely used for low gas flows where high accuracy is not important. Rotameters can be specified with nominal connections of 6.4 to 101.6 mm ($^1/_4$ to 4 in). Their accuracy ranges from 1 to 10 percent depending on the type and model selected.

4.6.2.

Rotameters are often used for measurement of purge gasses, stripping gas, chemical additives, and other small flow applications.

4.6.3.

Armored rotameters can be used if remote signaling is required. Armored rotameters that give only local indication are also available.

4.7. Vortex

The vortex shedding meter offers a low installed cost in comparison to an orifice meter, particularly in lines below 152 mm (6 in). This type generally offers minimal fixed line pressure loss. In some cases, the same meter can be used on both gas and liquids; however, in the case of liquids, line pressures shall be such that no cavitation can exist. Vortex shedding meters require a fully developed flow profile; this means that the upstream and downstream lengths are critical. Required upstream lengths can vary from 5 to 150 pipe diameters. Refer to section 2.24 of the Chilton Process Measurement Handbook for assistance.

4.8. Mass

4.8.1.

Direct mass flow meters are relatively expensive, ranging from $2,500 to $8,000 (U.S.). However, the advantages of direct mass flow measurement are self evident. Accuracies of ± 0.25 percent of reading are available.

4.8.2.

Mass flow meter use is limited in production and processing facilities, primarily due to cost.

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4.9. Magnetic

4.9.1.

In general, if the liquid conductivity is equal to or greater than 20 micro siemens per cm, a magnetic meter can be used. Magnetic flow meters are not affected by viscosity or consistency. In addition, changes in flow profile do not affect the meter performance. However, as with the case of mass meters, the unit costs are relatively high, varying from approximately $4500 to $120,000 (U.S.) depending on size.

4.9.2.

Magnetic flow meters have limited use in production and processing facilities because hydrocarbons are nonconductive.

4.10. Ultrasonic

As with most flow meters, the ultrasonic meter is sensitive to the flowing profile. Upstream length can vary from 10 to 20 pipe diameters, and the accuracy is greatly affected by solids and air bubbles in the flowing fluid. Since unit costs can vary from approximately $4,000 to $12,000 (U.S.) and installation is critical, these meters are seldom used in production and processing plants.

4.11. Thermal

Although thermal flow meters are suitable for both gas and liquid applications, there use in production and processing facilities is limited. Meter unit costs range from approximately $4,000 to $8,000 (U.S.).

4.12. Dump Meters

Dump meters are sometimes built into the bottom of vertical test separators and treaters to provide measurements for allocation purposes. Care shall be exercised to assure that while the meter vessel is dumping (i.e., level falling from the high level switch to the low level switch) the liquid that builds up in the vessel because the vessel outlet to the meter is blocked does not cause a process upset.

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4.13. Flow Transmitters

4.13.1.

Flow transmitters allow the readout or totalization device to be located in a convenient remote location while the primary device is located where ease of mechanical connection is considered.

4.13.2.

Transmitters for differential pressure indicative of flow convert the actual sensed differential pressure to either a 20 to 100 kPa (3 to 15 psig) or 4 to 20 mA signal. The signal can then be transmitted by tubing or wire to the receiver.

4.13.3.

Positive displacement and turbine flow meters use either contact closures or electronic pulses for transmission rather than 20 to 100 kPa (3 to 15 psig) or 4 to 20 mA signals. Special flow sensors use a wide variety of schemes for transmission; these are described in the vendors' literature. The receivers for these devices usually provide 4 to 20 mA analog output if it is needed for input to recorders, controllers, or other analog instruments.

4.13.4.

The use of pneumatic transmitters is decreasing; however, a number of manufacturers still make them for the replacement market, and some new installations are still being made. Pneumatic transmission may be advantageous when existing equipment is pneumatic and operating personnel are familiar with pneumatics.

4.13.5.

The sensing element's wetted parts shall be compatible with the process fluids. Type 316 stainless steel is the most universally acceptable material for produced fluids. Most manufacturers provide a compatibility chart with their recommendations. The transmitter body is usually carbon steel or stainless steel. Carbon steel is adequate for most applications. Stainless steel bodies are sometimes needed if the environment is severe.

4.13.6.

Several companies offer microprocessor-based transmitters, sometimes called "smart transmitters." These transmitters can be remotely programmed and/or calibrated for any desired range, either by the main process computer or by a special programmer. These transmitters are usually used in Distributed Control System (DCS) applications.

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4.14. Flow Controllers

A flow controller is a device that senses the flow in the process and develops an output that controls a device to regulate that flow. The sensing element is one of the various types discusses in Section 3, "Principles of Operation." The control device, or end element, is usually a pneumatic control valve. The controller output is usually either a 20 to 100 or 40 to 200 kPa (3 to 15 or 6 to 30 psig) pneumatic signal. In the case of electronic controllers, the output is 4 to 20 or 10 to 50 mA.

4.15. Flow Indication

4.15.1.

An indication of flow rate can be obtained by a differential pressure gauge with a 0 to 10 square root dial.

4.15.2.

Turbine meters can be provided with an electronic flow rate/cumulative flow readout mounted either locally or remotely. Positive displacement meters can be specified with a mechanically linked dial indicating flow rate and/or cumulative flow.

4.15.3.

Local flow rate indication is built into variable area meters, and special flow meters are normally purchased with special local or remote indicators for flow rate and/or cumulative flow.

4.15.4.

Remote indication involves a transmitter and a receiver. The receiver is usually located on a control panel and selected to match the other control panel instruments.

4.15.5.

Site flow indicators are common for utilities and vessel drain systems.

4.16. Flow Switches

All instruments that can measure flow can be used as a switch or to activate a switch. However, in applications where only a switch is needed, a direct-acting flow switch shall be employed. The expected cost range of these devices varies from approximately $150 to $450 (U.S.).

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4.17. Flow Provers

4.17.1. General

1. Liquid flow meters, usually turbine meters, particularly those used for custody transfer, shall be calibrated to satisfy the buyer, seller, and applicable government regulations. This is done by comparing the flow measured by the meter to a "known" value. In the United States, a method of calibration of flow meters traceable to the National Bureau of Standards is usually used. Allocation and other meters shall be "proven" periodically to assure that they are still reading flow rates and volumes within acceptable accuracy.

2. Primary elements of orifice plates and flow meters are inspected periodically to assure that the dimensions of tubes and surfaces, along with plate sharpness, flatness, and other dimensions, have not changed due to corrosion, erosion, solids buildup, pressure surges, or hydrate or ice damage. Secondary elements (chart recorders, pressure transmitters, etc.) are checked and recalibrated to known standards.

3. Meters can be proven using a master meter, bidirectional prover loop (ball prover), or calibration tank. API standards discuss meter proving methods.

4.17.2. Master Meter Prover

To prove with a master meter, the piping is arranged so that a calibrated meter can be installed in series with the meter to be calibrated. The "Master Meter" is calibrated with a sphere prover or by other means at a more convenient location. This method requires an additional meter and considerable transportation and installation effort but avoids the installation of a dedicated prover for each group of meters.

4.17.3. Ball Prover

1. A bidirectional ball prover is a u-shaped pipe with a calibrated volume between two limit switches. Flow is directed through the meter into the prover. The flow pushes a ball back and forth through the prover between the limit switches as controlled by a four way valve. The volume measured by the meter is compared to the volume of the prover. The design of the ball prover and its connection to the system is beyond the scope of this tutorial.

2. Ball provers are extremely accurate, but they are costly items, and they are normally installed only at points of custody transfer of large volumes of crude oil. Field production equipment is routinely equipped with prover connections. A portable prover is brought to the location on a periodic basis to prove the meter.

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4.17.4. Calibration Tanks

1. Another method of proving a meter is to flow the liquid into a storage tank that can be accurately gauged. Then the flow rate indicated by the meter over a period of time can be compared to the volume accumulated in the storage tank. This method is less accurate than a ball prover but may be used as a meter check in the same way.

2. The API Manual of Petroleum Measurement Standards presents detailed procedures for measuring the volume of liquid contained in a tank. This procedure is called "tank gauging" and is very commonly used for custody transfer at small production facilities that do not have "Automatic Custody Transfer" facilities. Tank gauging is used in inventory determination, meter checking, and verification.

3. Liquid is directed to a tank that has been previously "strapped." Strapping is a procedure also detailed by API for developing a table converting measured height of liquid in a specific tank to volume. By measuring the height of liquid before and after either filling or emptying the tank, one may determine the volume of displaced liquid.

4. In gauging a tank or using a tank for proving a meter, the system shall be designed and operated so that simultaneous flow into and out of the tank does not occur. It is normally necessary to measure the liquid temperature and convert the recorded volume to volume at a standard temperature.

4.18. Flow Totalizing

4.18.1.

The standard method for determining the cumulative flow for pneumatic differential pressure meters is to record the differential pressure, static pressure, and temperature with a chart recorder. The charts are read with an Emco-McGaughty Integrator to average the flow rate over time to determine the total quantity transferred. The accuracy of the measurement depends on how stable the readings are. Since the differential pressure reading may fluctuate a great deal, especially on gas lift wells, the accuracy of this type of integration is not very high.

4.18.2.

Electronic instruments that integrate the data from differential pressures, static pressure, and temperature transmitters are usually microprocessor based and have both mechanical counters and electronic readouts. The functions that are available vary widely from one manufacturer to another. Common features are electronic readouts of instantaneous flow rate and accumulated flow, with output in any desired engineering units, computation by any desired formula, 4 to 20 mA flow rate output for remote reading or

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control, contact outputs for remote totalizers or alarms, and summing for multiple meter runs.

4.18.3.

Positive displacement meters develop enough torque to operate a mechanical flow totalizer. The totalizer is connected through a gearing system to calibrate the counter in the desired engineering units. A second counter that compensates the reading for temperature by using a bulb temperature sensor and a clutch arrangement can be added. This feature is called Automatic Temperature Compensation (ATC).

4.18.4.

Pulse transmitters that close a contact or send an electronic pulse can be added for actuation of a remote device. These devices are especially important for ball provers and sampling devices. The collection of these devices is mounted on the top of the positive displacement meter and is called "the stack."

4.18.5.

Positive displacement meters can provide remote flow rate measurement or totalization in much the same manner as differential pressure devices. The primary difference is that the flow input signal is a pulse that represents a discrete volume of fluid.

4.18.6.

Turbine meters are treated similarly to positive displacement meters for remote reading. The pulse rate for turbine meters is usually higher than for positive displacement meters. Turbine meters do not develop enough torque to operate mechanically connected devices.

5. Meter Sizing

Most flow meters are specified by the manufacturer's catalog data for specific flow properties, flow ranges, and operating pressures. Orifice meters require the engineer to chose a pipe diameter and orifice size.

5.1. Orifice Plate Sizing

Sizing calculations for gas orifice flow meters are normally based on AGA 3 standard equations, while those for liquid flow are typically based on the procedures developed by L.K. Spink.

5.1.1. Selecting Beta Ratio

Orifice meters are usually sized by selecting a pipe diameter and a diameter ratio, "beta," which is defined as the ratio of the orifice bore diameter to the pipe inside diameter. These parameters are all interrelated by the flow equations. AGA 3 states that sufficient accuracy can be obtained with beta ratios between 0.15 and 0.75 for flange taps and between 0.2 and 0.67 for pipe taps. Some gas sales contracts may limit the range of beta ratios even further.

5.1.2. Selecting Orifice Differential Pressure (DP)

1. The most common differential pressure h_w meter range for flow measurement is 0 to 25 kPa (0 to 100 in of water). This is a convenient range for flow calculations and usually can be achieved with an acceptable beta ratio without changing the line size.

2. The flow rate formulas are based on the flow through the orifice being well below sonic velocity. A rule of thumb to ensure subsonic flow is to require the maximum meter reading in inches of water not to exceed the static flowing pressure in psia. For flowing pressures below 690 kPa (100 psia), a meter range of 0 to 12.5 kPa (0 to 50 in of water) or 0 to 5 kPa (0 to 20 in of water) shall be considered.

3. For higher pressures, if the required measurement cannot be achieved with 0 to 25 kPa (0 to 100 in of water), an acceptable beta ratio, and a line sized meter run, then a higher meter range may be considered.

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Appendix A–Example Problems - Metric Units

1. Gas Orifice Plate Calculation

Determine an orifice plate diameter for the following conditions:

Gas flowing temperature = 38°C

Gas flowing pressure = 6900 kPa(G)

Gas specific gravity = 0.65

Gas flow rate = 12000 std m^3/hr

H_2S and CO_2 are not present

Base pressure = 100 kPa

Base temperature = 15°C

The meter run will be installed at the base of a glycol contactor, where the piping shall include two ells in different planes.

Assumptions:

1. Flange taps are required
2. Carbon steel flange material and 316 stainless steel orifice plate will be acceptable
3. Ratio of specific heats $C_p/C_v = 1.3$
4. Bellows type manometer will be used
5. Static pressure tap will be located up stream
6. Differential pressure range 0 to 25 kPa is preferred
7. Pipeline ID = 102.3 mm

Refer to AGA Report No. 3 (API MPMS 14.3.3) for specific details on gas flow orifice calculations.

The basic equation specified by AGA 3 (API MPMS 14.3.3) is:

(AGA 3, Equation 59)

$$Q_h = C' \left(h_w P\right)^{\frac{1}{2}}$$

where :

$Q_h = rate\ of\ \ flow\ at\ base\ conditions, SCFH$

$C' = orifice\ \ flow\ constant$

$h_w = measured\ differential\ \ pressure, inches\ H_2O$

$P = static\ \ pressure\ ,\ psia$

The orifice flow constant is calculated by the following equation:

$$C' = F_b\ F_r\ Y\ F_{pb}\ F_{tb}\ F_{tf}\ F_{gr}\ F_{pv}$$

where :

$F_b = basic\ orifice\ \ factor$

$F_r = Reynolds\ number\ \ factor$

$Y = expansion\ \ factor$

$F_{pb} = pressure\ base\ \ factor$

$F_{tb} = temperature\ base\ \ factor$

$F_{tf} = \ flowing\ temperature\ \ factor$

$F_{gr} = real\ \ gas\ relative\ density\ \ factor$

$F_{pv} = supercompressibility\ \ factor$

The values of the various correction factors are dependent on the orifice configuration, pressure tap location, and operating conditions. To simplify this analysis, only concentric round orifices are considered. This is the most common and accepted configuration for accurate flow measurements. AGA 3 includes all these correction factors in tabular form; refer to these tables as required.

Assume orifice diameter d = 57.15 mm, diameter ratio $\beta = d/D = 0.5587$

Then:

$F_b = 1089.9 \ \ Table\ B_1$

$F_r = 1 \quad Table\ B_2$

$Y = 0.999 \quad Table\ B_3$

$F_{pb} = 1.01 \quad Table\ D_1$

$F_{tb} = 0.998 \ \ Table\ D_2$

$F_{tf} = 0.9636 \quad Table\ D_3$

$F_{gr} = 1.2403 \quad Table\ D_4$

$F_{pv} = 1.0609 \quad Table\ D_5$

So:

$C' = 1392$

$$Q_h = (1392)(100 \times 1014.73)^{\frac{1}{2}}$$
$$= 443{,}400\ SCFH$$

$$= 10.6\ MMSCF\ \frac{1192\ std\ m^3 / hr}{1MMSCFD} = 12{,}600\ std\ m^3 / hr$$

Therefore, the orifice size of 57.15 mm is acceptable for the given flow rate.

2. Liquid Orifice Plate Calculations

Check an orifice plate sized for water service as follows:

Flowing Pressure = 297 kPa(A)

Flowing Temperature = 27°C

Line Size = 10.16 cm

Normal Flow Rate = 34 m^3/hr

Orifice Pressure Drop = 12 kPa

Orifice Bore = 6.67 cm (β= 0.6565)

Make the same basic assumptions as in Example 1.

The accepted industry standard used for liquid flow metering is L.K. Spink's Plant Equation, which for metric units is:

(Production Facilities Bookware Series, Flow Instrumentation, Equation 1)

$$Q_M = \frac{0.4\, S \left(G_f\right)^{\frac{1}{2}} F_a\, D^2 \left(h_w\right)^{\frac{1}{2}} F_m}{G_L}$$

where :

$Q_M = maximum\ liquid\ \ flow\ rate, m^3 / hr$

$S = orifice\ \ flow\ coefficient = 0.295\ (Spink, Table\ 12)$

$G_f = specific\ gravity\ of\ \ fluid\ \ at\ \ flowing\ temperature = 1$

$G_L = specific\ gravity\ of\ \ fluid\ \ at\ the\ base\ temperature = 1$

$F_a = correction\ \ factor\ \ for\ change\ in\ dimensions\ of\ \ the\ \ primary\ device$
$with\ change\ in\ temperature = 1$

$h_w = pressure\ drop\ across\ orifice, kPa = 12$

$D = upstream\ \ pipe\ diameter, cm = 10.16$

$F_m = manometer\ \ factor = 1$

This equation can be used with the following provisions:

1. The viscosity of the liquid does not exceed the limits shown in Figure B-2239, p. 140 of Spink's Handbook. When liquid viscosities in excess of these limits are encountered, positive displacement meters shall be used. Viscosity limits are for ± 1 percent calculation tolerance.
2. The Reynolds number through the orifice is greater than 10,000.

The factor S corrects for the coefficient of discharge.

Refer to Chapter 10 of the Spink Handbook for details as needed.

$$Q_m = \frac{0.4\,(0.295)(1)^{\frac{1}{2}}\,(1)(10.16)^2\,(12)^{\frac{1}{2}}\,(1)}{1}$$

$$Q_m = 42.2\ m^3 / hr$$

Appendix B–Example Problems - Customary Units

1. Gas Orifice Plate Calculation

Determine an orifice plate diameter for the following conditions:

Gas flowing temperature = 100°F

Gas flowing pressure = 1000 psig

Gas specific gravity = 0.65

Gas flow rate = 10 MMSCFD

H_2S and CO_2 are not present

Base pressure = 14.73 psia

Base temperature = 60°F

The meter run will be installed at the base of a glycol contactor, where the piping shall include two ells in different planes.

Assumptions:

1. Flange taps are required
2. Carbon steel flange material and 316 stainless steel orifice plate will be acceptable
3. Ratio of specific heats $C_p/C_v = 1.3$
4. Bellows type manometer will be used
5. Static pressure tap will be located up stream
6. Differential pressure range 0 to 100 in water column is preferred
7. Pipeline ID = 4.026 in

Refer to AGA Report No. 3 (API MPMS 14.3.3) for specific details on gas flow orifice calculations.

The basic equation specified by AGA 3 (API MPMS 14.3.3) is:

(AGA 3, Equation 59)

$$Q_h = C' \left(h_w P\right)^{\frac{1}{2}}$$

where :

$Q_h = rate\ of\ \ flow\ at\ base\ conditions, SCFH$

$C' = orifice\ \ flow\ constant$

$h_w = measured\ differential\ \ pressure, inches\ H_2O$

$P = static\ \ pressure\ ,\ psia$

The orifice flow constant is calculated by the following equation:

$$C' = F_b\ F_r\ Y\ F_{pb}\ F_{tb}\ F_{tf}\ F_{gr}\ F_{pv}$$

where :

$F_b = basic\ orifice\ \ factor$

$F_r = Reynolds\ number\ \ factor$

$Y = expansion\ \ factor$

$F_{pb} = pressure\ base\ \ factor$

$F_{tb} = temperature\ base\ \ factor$

$F_{tf} = \ flowing\ temperature\ \ factor$

$F_{gr} = real\ \ gas\ relative\ density\ \ factor$

$F_{pv} = supercompressibility\ \ factor$

The values of the various correction factors are dependent on the orifice configuration, pressure tap location, and operating conditions. To simplify this analysis, only concentric round orifices are considered. This is the most common and accepted configuration for accurate flow measurements. AGA 3 includes all these correction factors in tabular form; refer to these tables as required.

Assume orifice diameter d = 2.25 in, diameter ratio $\beta = d/D = 0.5589$

Then:

$F_b = 1089.9 \;\; Table\ B_1$

$F_r = 1 \quad Table\ B_2$

$Y = 0.999 \quad Table\ B_3$

$F_{pb} = 1.01 \quad Table\ D_1$

$F_{tb} = 0.998 \;\; Table\ D_2$

$F_{tf} = 0.9636 \quad Table\ D_3$

$F_{gr} = 1.2403 \quad Table\ D_4$

$F_{pv} = 1.0609 \quad Table\ D_5$

So:

$C' = 1381.7873$

$$Q_h = (1381.7873)(100 \times 1014.73)^{\frac{1}{2}}$$
$$= 440{,}165 \; SCFH$$

$$= 10.56 \; MMSCFD$$

Therefore, the orifice size of 2.25 in is acceptable for the given flow rate.

2. Liquid Orifice Plate Calculations

Check an orifice plate sized for water service as follows:

Flowing Pressure = 39.7 psia

Flowing Temperature = 80°F

Line Size = 4 in

Normal flow rate = 150 gpm

Orifice Pressure Drop = 50 inches H_2O

Orifice Bore = 2.625 in ($\beta = 0.65625$)

Make the same basic assumptions as in Example 1.

The accepted industry standard used for liquid flow metering is L.K. Spink's Plant Equation, which is:

Spink Handbook, Equation 6)

$$Q_M = \frac{5.667\, S\, (G_f)^{\frac{1}{2}}\, F_a\, D^2\, (h_w)^{\frac{1}{2}}\, F_m}{G_L}$$

where :

$Q_M = maximum\ liquid\ \ flow\ rate, m^3 / hr$

$S = orifice\ \ flow\ coefficient = 0.295\ (Spink, Table\ 12)$

$G_f = specific\ gravity\ of\ \ fluid\ at\ \ flowing\ temperature = 1$

$G_L = specific\ gravity\ of\ \ fluid\ at\ the\ base\ temperature = 1$

$F_a = correction\ \ factor\ \ for\ change\ in\ dimensions\ of\ \ the\ \ primary\ device$
$with\ change\ in\ temperature = 1$

$h_w = pressure\ drop\ across\ orifice, inches\ of\ \ H_2O$

$D = upstream\ \ pipe\ diameter, inches = 4$

$F_m = manometer\ \ factor = 1$

This equation can be used with the following provisions:

1. The viscosity of the liquid does not exceed the limits shown in Figure B-2239, p. 140 of Spink's Handbook. When liquid viscosities in excess of these limits are encountered, positive displacement meters shall be used. Viscosity limits are for ±1 percent calculation tolerance.
2. The Reynolds number through the orifice is greater than 10,000.

The factor S corrects for the coefficient of discharge.

Refer to Chapter 10 of the Spink Handbook for details as needed.

$$Q_m = \frac{5.667\,(0.295)\,(1)^{\frac{1}{2}}\,(1)(4)^2\,(50)^{\frac{1}{2}}\,(1)}{1}$$

$$Q_m = 189\ gpm$$

Instrumentation Piping and Tubing Fittings

MP 32-P-19

April 1998

Scope

This Mobil Engineering Practice (MEP) covers the basic requirements for the design of instrument air piping, pneumatic signal piping and piping that connects instruments to pressure piping or equipment.

Throughout this Practice, the term "piping" includes tubing and NPS (nominal pipe size in inches) piping. Analyzer sample probes and transport systems are not covered (see MP 32-P-06).

Version 0

Table of Contents

Scope **1**

1. References **4**

1.1. MEPS–Mobil Engineering Practices 4

1.2. API–American Petroleum Institute 4

1.3. ASME–American Society of Mechanical Engineers 4

1.4. ASTM–American Society for Testing and Materials 4

1.5. ISA–Instrument Society for Measurement & Control 5

2. General **5**

2.1. Fitting Approval 5

2.2. Preventing Fluid Traps 5

2.3. Gauge Glass Standpipes 5

2.4. Pressure Differential Transmitter Connections 5

2.5. Thermowell Connections 6

3. Instrument Pressure Piping **6**

3.1. Design 6

3.2. Materials 7

3.3. Tubing Valves 7

4. Air Supply and Signal Tubing **8**

4.1. Design 8

4.2. Materials 8

5. Pipe Supports **9**

6. Pressure Testing **10**

7. Winterizing and Fire Protection **10**

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Appendix: Maximum Allowable Pressures for Commonly Used Sizes of ASTM A269 Type 316 SS Instrument Pressure Tubing 11

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1. References

The following publications form a part of this Practice. Unless otherwise specified herein, use the latest edition.

1.1. MEPS–Mobil Engineering Practices

MP 16-P-30A	Piping - Materials and Service Classifications (M&R)
MP 32-P-01	General Requirements for Instrumentation
MP 32-P-06	Process Analyzers
MP 70-P-05	Fireproofing

1.2. API–American Petroleum Institute

API RP 552	Transmission Systems First Edition

1.3. ASME–American Society of Mechanical Engineers

ASME B31.3	Process Piping

1.4. ASTM–American Society for Testing and Materials

ASTM A269	Standard Specification for Seamless and Welded Austenitic Stainless Steel Tubing for General Service
ASTM B68	Standard Specification for Seamless Copper Tube, Bright Annealed
ASTM B75 REV A	Standard Specification for Seamless Copper Tube
ASTM B88	Standard Specification for Seamless Copper Water Tube

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1.5. ISA–Instrument Society for Measurement & Control

ISA RP7.1	Pneumatic Control Circuit Pressure Test; (Approved July 1, 1956) Superseded by: S7.0.01: 1996

2. General

The design and installation of instrument piping systems shall be in accordance with the requirements of this MEP, project specifications and ASME B31.3, except where superceded by more stringent local regulations.

Instrument piping design shall be in accordance with MP 32-P-01. Piping component selection shall conform to MP 16-P-30A.

2.1. Fitting Approval

Pipe and tubing fitting manufacturers shall be approved. All tubing fittings and components in any tubing assembly shall be from the same manufacturer. The contractor shall standardize on a single tubing fitting manufacturer for the work.

2.2. Preventing Fluid Traps

Piping connected to vessel nozzles shall be designed and installed to prevent fluid pockets or traps.

2.3. Gauge Glass Standpipes

Level instruments and gauge glass standpipes may use common vessel nozzle connections. Gauge glass standpipes shall not be less than NPS 2, Schedule 80 pipe. (Exception: Stainless steel standpipes may be Schedule 40 pipe.)

2.4. Pressure Differential Transmitter Connections

Vessel connections for pressure differential transmitters or indicators shall not be used for other purposes, such as drains or pumpout lines.

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2.5. Thermowell Connections

- In carbon steel piping services, where screwed fittings are acceptable (MP 16-P-30A), NPS 1 thermowell connections may be used.
- Where the line classes require all fittings below NPS 2 to be of the socket welded type, thermowells shall be flanged, NPS 1 $^1/_2$.
- In alloy piping and lined piping (including cement-lined), thermowell connections shall be flanged, NPS 1 $^1/_2$.

3. Instrument Pressure Piping

3.1. Design

Instrument pressure piping, up to and including the first instrument block valves, shall conform to the same design and material specifications as the connected lines or equipment and shall be NPS $^3/_4$ pipe minimum. (Exception: Connections to orifice flanges and other differential metering devices may be NPS $^1/_2$.)

The design pressure and temperature for instrument pressure piping downstream of the first block valve shall be the same as for the connected process line or equipment.

Instrument pressure piping downstream of the process tap block valve shall be NPS $^1/_2$ pipe or 12 mm ($^1/_2$ in) OD tubing minimum. All tubing and pipe shall be properly supported and protected from accidental damage. (Exception: 9 mm [$^3/_8$ in] tubing may be used where approved.)

3.1.1. Block Valves

Block valves shall be installed as closely as possible to the connected process lines or equipment. Welding is not allowed downstream of the block valves.

3.1.2. Instrument Connections

Small instrument connections to piping shall have adequate mechanical strength to preclude damage from fatigue, vibration and incidental mechanical impact.

Instrument connections that require periodic rodding to prevent plugging shall be considered individually by the contractor. The details of proposed installations shall be approved.

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3.2. Materials

Instrument pressure piping and tubing shall be suitable for the process fluid transported and for the environment in which it is installed. In sweet natural gas, the instrument pressure piping downstream of the first instrument block valve shall consist of Type 316 stainless steel tubing, fittings and valves. Stainless steel shall not be used in HF acid service.

In sour (H_2S) or other corrosive services, the instrument pressure piping downstream of the first instrument block valve, the tubing, fittings and wetted parts of valves shall be Alloy 825 or another higher corrosion-resistant alloy suitable for the pressure and temperature. (Exception: In dehydrated sour gas applications, ASTM A269 seamless 316 stainless steel may be used where the pressure class does not exceed ANSI 150.)

Stainless steel shall not be used in hydrofluoric acid service or in high chloride environments.

When pipe is used for instrument pressure piping downstream of the instrument block valve, the piping shall conform to the material specifications of the connected line or equipment.

The instrument pressure piping materials for all other services shall be approved.

Tubing used for instrument pressure piping shall be ASTM A269, seamless Type 316 stainless steel. Any use of welded tubing shall be approved and shall be limited to use in long straight tubing runs and/or long radius bends. The use of welded tubing for small radius bends shall be avoided. The maximum pressure rating of the tubing based on the minimum tube wall thickness shall conform to ASTM A269. Minimum nominal wall thickness shall be 0.75 mm (0.028 in) for 6 mm ($^1/_4$ in) OD tubing and 1 mm (0.035 in) for 10 mm ($^3/_8$ in) or 12 mm ($^1/_2$ in) OD tubing.

3.3. Tubing Valves

- The valve body, stem and trim shall be of the same material as the tubing, but in no case shall it be less than Type 316 stainless steel. The valve stem shall be of blowout-proof design.
- Stem packing and seat material shall be capable of withstanding the maximum temperature and pressure encountered in service.
- Valves shall have integral bite-type tubing fittings or pipe-threaded ends for tubing fittings.

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4. Air Supply and Signal Tubing

4.1. Design

Pneumatic signal tubing shall conform to the requirements herein and to API RP 552, Section 21.

Air supply headers and laterals shall be arranged to allow air to be blown through a full-size opening to facilitate final cleaning of the air system.

Instrument air branch supply lines shall be taken from the top of the header. A ball valve shall be used against the header at each air line takeoff. A round/oval handle for the ball valve may be considered to prevent accidental valve closures. Where a single takeoff from the main supply header serves more than one instrument, the installation of an instrument air manifold shall be considered. Branch lines from the main header or manifold to individual instruments shall be separately valved.

Supply lines from an instrument air header to instruments shall be NPS $^1/_2$, minimum. All branch supply lines shall have low-point drain valves.

Each instrument shall have a filter regulator equipped with a 2-inch dial pressure gauge. Supply lines to instruments shall terminate with shutoff valves located not more than 900 mm (36 in) from the instruments. Piping from the shutoff valve shall be 10 mm ($^3/_8$ in) OD tubing. The tubing shall be installed with sufficient flexibility to allow for normal piping/equipment movements.

Pneumatic signal transmission tubing between instruments and junction boxes shall be minimum 6 mm ($^1/_4$ in) OD tubing.

Air supply and signal transmission lines shall be routed to minimize exposure to accidental impact damage.

4.2. Materials

Air supply and signaling tubing shall be seamless 316 stainless steel conforming to ASTM A269. Copper tubing may be used where specifically approved for the application.

Where copper tubing is approved, the tubing shall be soft annealed, nonarsenic and shall meet ASTM B68, ASTM B75 REV A or ASTM B88 requirements. Minimum nominal wall thickness shall be 1 mm (0.035 in) for 6 mm ($^1/_4$ in) OD tubing and 1.5 mm (0.049 in) for 10 mm ($^3/_8$ in) or 12 mm ($^1/_2$ in) OD tubing.

Copper tubing shall be protected with a black polyethylene or polyvinyl chloride (PVC) jacket with a minimum thickness of 1 mm ($^1/_{32}$ in). If approved, the jacket may be omitted in non-corrosive environments.

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Stainless steel tubing shall be ASTM A269 Type 304 or Type 316 annealed, seamless or welded. Minimum nominal wall thickness shall be 0.75 mm (0.028 in) for 6 mm ($^1/_4$ in) OD tubing, and 1 mm (0.035 in) for 10 mm ($^3/_8$ in) or 12 mm ($^1/_2$ in) OD tubing.

Aluminum and plastic tubing shall not be used.

4.2.1. Pipe and Tubing Fittings

- Brass bite-type compression fittings shall normally be used with copper tubing in non-corrosive and corrosive environments. Wherever brass fittings are used with PVC covered copper tubing, PVC boots are to be provided.
- Bite-type compression fittings in highly corrosive environments, marine and chloride bearing environments shall be Type 316 stainless steel. Stainless steel fittings shall be used with stainless steel tubing in corrosive environments.

4.2.2. Tubing Valves

- Brass-body globe, ball or needle valves shall normally be used in onshore noncorrosive environments.
- Valves in highly corrosive environments, marine (offshore) and chloride bearing environments shall have Type 316 stainless steel bodies.
- Tubing valves shall have Teflon or graphite packing, stainless steel stems and TFE stem tips or seats where tight shutoff is required. End connections may be either pipe threaded or integral compression bite-type tubing fittings.

5. Pipe Supports

Individual instrument lines generally shall not be supported from larger lines. However, in remote locations, individual lines may be supported by lines NPS 2 and larger. Tubing shall be supported in accordance with the recommendations in API RP 552, Section 21. The method of support shall be approved.

In areas where it is possible for mechanical damage to occur, lines shall be protected by a continuous support (for example, a structural steel angle or channel).

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6. Pressure Testing

Testing of instrument pressure piping and air supply piping shall be in accordance with the requirements of the project specifications.

Pressure testing of signal transmission systems shall be in accordance with ISA RP7.1.

7. Winterizing and Fire Protection

Tubing fireproofing requirements are covered in MP 70-P-05.

Instrument piping containing fluids that are normally static and subject to freezing shall be protected by heat tracing (or other heating methods) and insulated.

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Appendix: Maximum Allowable Pressures for Commonly Used Sizes of ASTM A269 Type 316 SS Instrument Pressure Tubing

The following maximum pressures are calculated based on minimum tube wall thickness specified in ASTM A269.

Table 1: Maximum Design Pressures

	Tubing Characteristics OD x WT		**Max. Design Pressure up to 149°C (300°F)[(1)]**	
	in	**mm[(2)]**	**kPa**	**psig**
Seamless	1/4 x 0.028	6.4 x 0.7	28,400	4,100
Seamless	1/4 x 0.035	6.4 x 0.9	36,000	5,200
Seamless	1/4 x 0.049	6.4 x 1.3	52,500	7,600
Seamless	3/8 x 0.028	9.5 x 0.7	18,000	2,600
Seamless	3/8 x 0.035	9.5 x 0.9	22,900	3,300
Seamless	3/8 x 0.049	9.5 x 1.3	33,200	4,800
Seamless	1/2 x 0.035	12.7 x 0.9	18,000	2,600
Seamless	1/2 x 0.049	12.7 x 1.3	25,600	3,700
Welded	1/4 x 0.028	6.4 x 0.7	22,200	3,200
Welded	1/4 x 0.035	6.4 x 0.9	29,100	4,200
Welded	1/4 x 0.049	6.4 x 1.3	42,200	6,100
Welded	3/8 x 0.028	9.5 x 0.7	14,600	2,100
Welded	3/8 x 0.035	9.5 x 0.9	18,700	2,700
Welded	3/8 x 0.049	9.5 x 1.3	27,000	3,900
Welded	1/2 x 0.035	12.7 x 0.9	14,600	2,100
Welded	1/2 x 0.049	12.7 x 1.3	20,800	3,000

NOTES:

1. At elevated temperatures, the above maximum pressures shall be multiplied by the following derating factors.

Design Temperature	204°°C (400°F)	260°C (500°F)	316°C (600°F)	371°C (700°F)	427°C (800°F)	482°C (900°F)	538°C (1000°F)
Derating Factor	0.965	0.895	0.850	0.815	0.795	0.775	0.765

2. Tubing dimensions shown in millimeters are converted from standard British tubing dimensions for reference and are not standard metric tubing dimensions.

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Instrument and Plant Air Systems

EPT 04-T-18

August 1998

Scope

This Mobil Engineering Practice Tutorial (EPT) describes the design of instrument air and plant air systems for Mobil refineries and chemical plants. It covers system requirements for compressors, aftercoolers, air receivers, filters, air dryers, distribution systems and criteria for developing air requirements. Typical system sketches are also included.

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Table of Contents

Scope **1**

Table of Tables **4**

1. References **5**

1.1. MEPS–Mobil Engineering Practices 5

1.2. ASME–American Society of Mechanical Engineers 5

1.3. ISA–Instrument Society of America 5

2. Definitions **5**

3. System Description **6**

3.1. Instrument Air System 6

3.2. Plant Air System 6

3.3. System Interconnections 6

4. System Design **9**

4.1. General 9

4.2. Capacity 10

4.3. Compressor Selection 12

4.4. Intercoolers and Aftercoolers 13

4.5. Air Receivers 14

4.6. Air Dryers 16

4.7. Plant Air and Instrument Air Distribution Systems 21

4.8. Controls and Instrumentation 24

4.9. Cooling Water Requirements 25

Appendix A: Air Requirements **26**

Appendix B: Plant Air Planning Sheet **31**

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Table of Figures

Figure 1: Compressed Air System with Centrifugal Air Compressors (Typical) 7

Figure 2: Compressed Air System with Reciprocating Air Compressors (Typical) 8

Figure 3: Amount of Moisture in Isothermally Compressed Air.....14

Figure 4: Safety Relief Valves–Air Expansion Service Due to Fire.....16

Figure 5: Typical Air Dryer 19

Figure 6: Loss of Air Pressure Due to Friction per 100 ft of Pipe and 100 psig Initial Pressure 23

Table of Tables

Table 1: Types of Dryers.....20

Table A–1: Instrument Air Requirements.....26

Table A–2: Pneumatic Tools: Plant Air Consumption in Quantities of Free Air*.....26

Table A–3: Typical Tool Load Factor.....28

Table A–4: Typical Unit Air Requirements (Based on Joliet Refinery Data) 29

1. References

The following publications form a part of this Tutorial. Unless otherwise specified herein, use the latest edition.

1.1. MEPS–Mobil Engineering Practices

MP 32-P-01	General Requirements for Instrumentation
MP 41-P-05	Packaged, Integrally Geared Centrifugal Air Compressors
MP 41-P-06	Packaged Positive Displacement Air Compressors
MP 41-P-10	Compressed Air Dryer-Regenerative Type
MP 57-P-02	Pressure Containing Equipment - Welding & Inspection

1.2. ASME–American Society of Mechanical Engineers

ASME B16.5	Pipe Flanges and Flanged Fittings NPS 1/2 Through NPS 24
ASME B31.3	Process Piping
ASME SEC VIII DIVISION 1	BPVC SECTION VIII Rules for Construction of Pressure Vessels DIVISION 1 Non-Interfiled (Boiler and Pressure Vessel Codes)

1.3. ISA–Instrument Society of America

ISA S7.3	Quality Standard for Instrument Air Superseded by: S7.0.01: 1996 R(1981)

2. Definitions

Air Compressor Package	A complete air compressor system, including compressor, driver, lubrication system, intercoolers, aftercoolers and compressor controls, generally skid mounted and delivered as a preassembled unit complete with interconnecting piping.
Load Factor	The ratio of the average demand for air to the peak demand over a specified period of time.
Pressure Dew Point	The temperature at which the water vapor in the air, at a given

	pressure will start to condense.

3. System Description

3.1. Instrument Air System

The instrument air system is a critical utility system. Therefore, the reliability of operation of the system components is of prime importance.

The quality of instrument air is critical to the operation of modern process plants. The air shall be clean, dry and free of oil to ensure that small lines, restrictions and nozzles will not be fouled or plugged by scale dirt, oil or water and that instruments and associated piping are not damaged in freezing climates. Use of instrument air shall be restricted to equipment that requires this quality of air.

The specified operating pressure of the instrument air system shall be maintained and the supply shall be protected. A continual drop in pressure will ultimately cause the total shutdown of process and utility consumers.

3.2. Plant Air System

The plant air system is primarily intended to supply clean air for the operation of air-powered tools. It may also be used to supply clean air to process and other users that do not require instrument air quality.

3.3. System Interconnections

Plant and instrument air systems are normally interconnected. The plant air supply is used as a backup to maintain the integrity of the instrument air system. There are a number of ways to accomplish this protection. Figures 1 and 2 show typical systems. It is essential that such interconnections be tied in upstream of the instrument air drying equipment. Tool air supplied with injected lubrication shall not be interconnected with instrument air systems.

Plant and instrument air systems may be combined into a single system for batch processes, such as are found in blending plants. The loss of instrument air will not result in a significant loss of production to a batch process, which has a low sensitivity to unpredicted shutdowns. In blending plants, the use of oil-flooded, rotary screw compressors requires Mobil approval. When these compressors are used in blending plants, a coalescing-type, self-cleaning oil filter/separator shall be provided in addition to the oil separation equipment that is a part of the compressor package.

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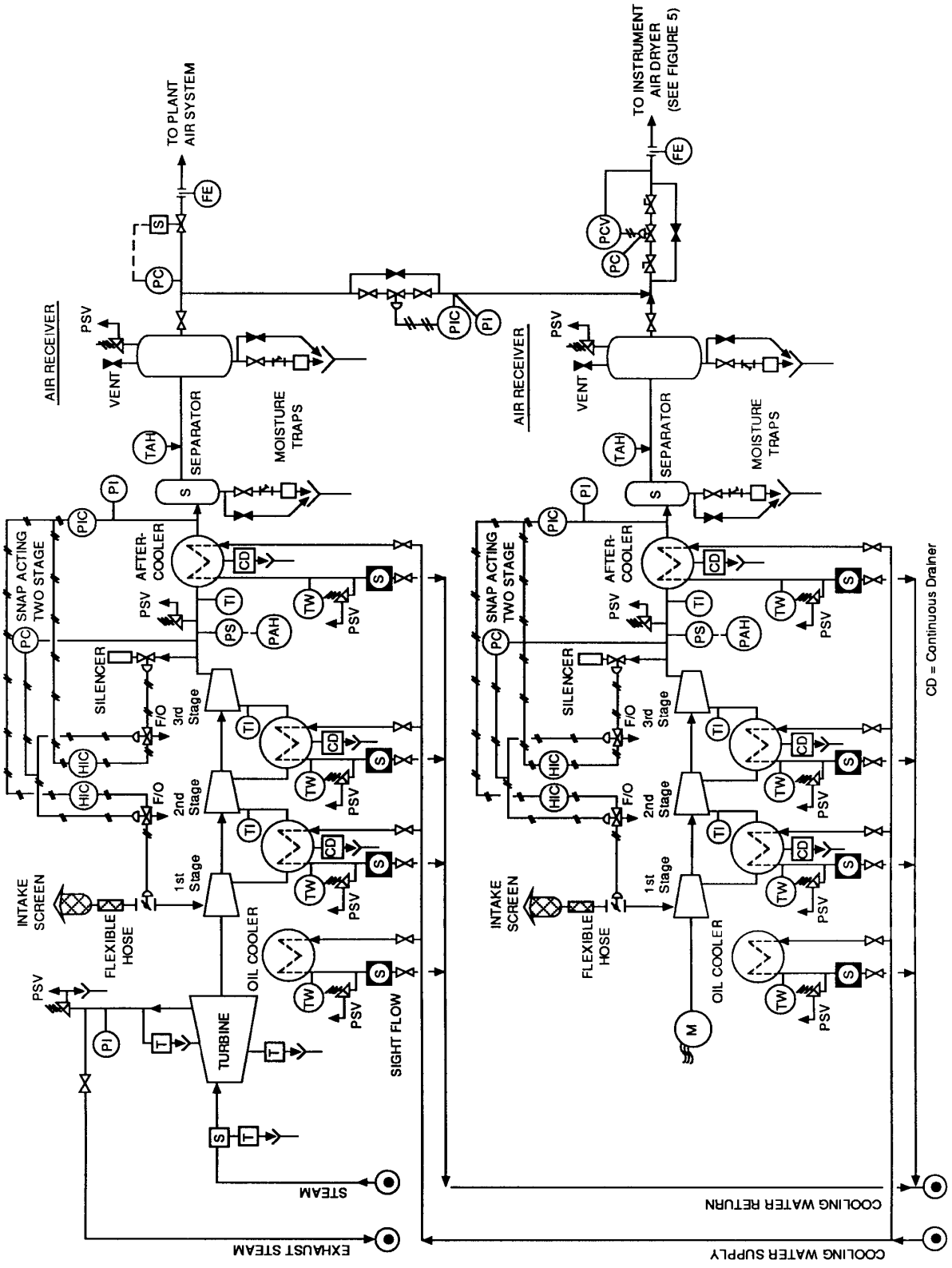

Figure 1: Compressed Air System with Centrifugal Air Compressors (Typical)

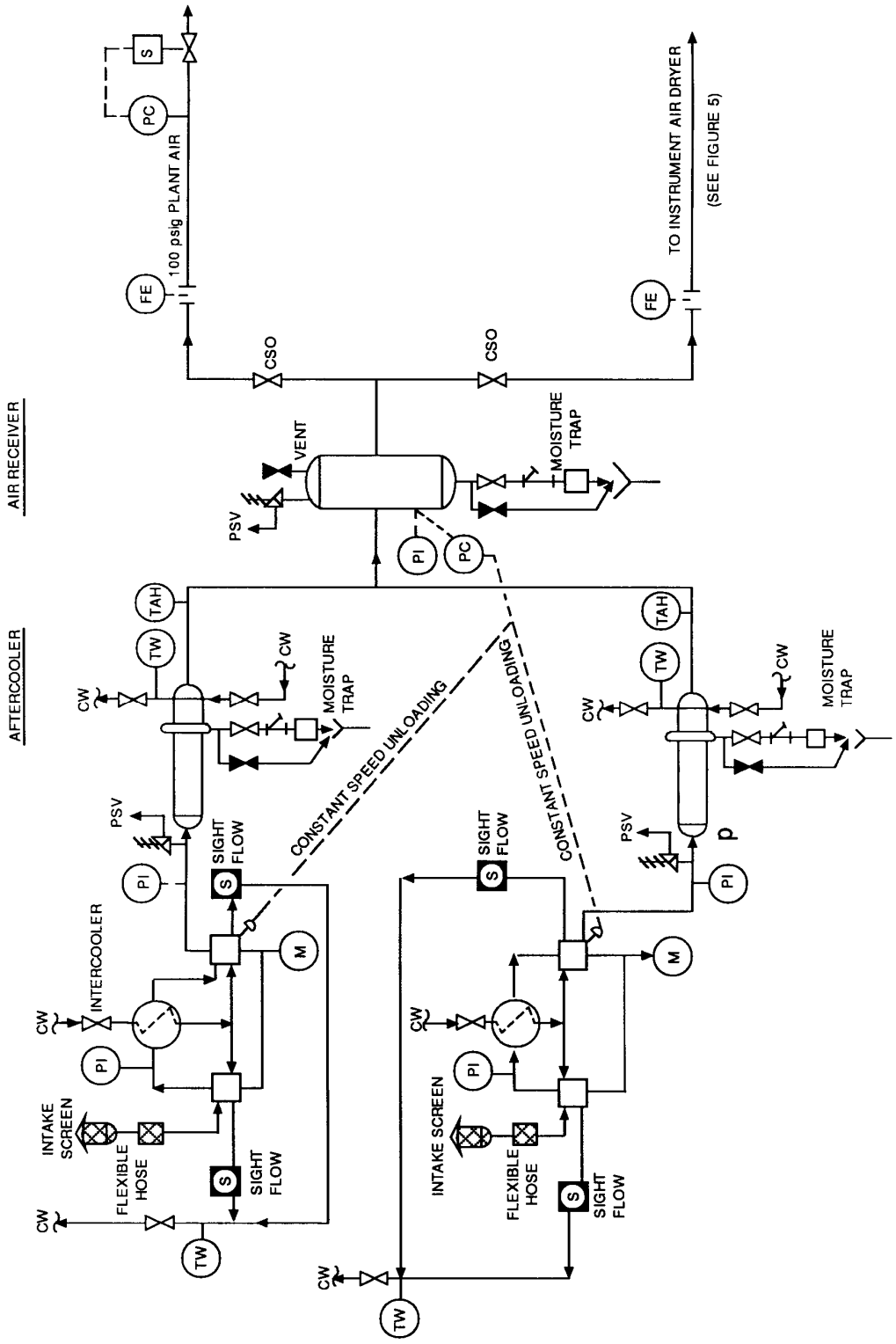

Figure 2: Compressed Air System with Reciprocating Air Compressors (Typical)

4. System Design

4.1. General

Instrument air and plant air shall not be used as breathing air by personnel. In some locations, regulatory authorities prohibit its use for pressurizing potable water systems.

Instrument air systems shall be designed for continuous operation during electric power outages. Where suitable steam is available, it shall be used as the source of power for the main compressor drivers.

- Slow rolling a steam turbine driver for automatic backup start on electric power failure is not recommended because of the high steam usage. The steam required for the turbine driver shall be taken from the most protected steam pressure level in the steam system.
- A Mobil Rotating Equipment Specialist shall be consulted in applications where steam turbine driver(s) for compressed air systems are being considered.

4.1.1. Instrument Air System Security

The security of the instrument air system shall be maintained on the loss of the operating air compressor.

The preferred method is to provide two 100 percent design capacity air compressors (one operating, one standby). Each shall be sized to serve both instrument and plant air systems, and each driver shall be powered from an alternate energy source.

- Each installation and project shall be individually evaluated as to the reliability of the primary power system. If the power source is found to be very reliable (such as redundant sources), an economic evaluation of two motor-driven compressors versus one motor and one steam turbine driven compressor shall be conducted. The overall cost effectiveness of each combination shall be determined.
- The standby compressor shall serve as an automatic backup, activated by a predetermined air system low-pressure signal. The economics of utilizing three 50 percent capacity compressors instead of two 100 percent machines shall be evaluated for large systems (over 4800 Nm^3/h [3000 scfm]).

4.1.1.1. Air Receiver Facility

An air receiver facility with sufficient storage to ensure an adequate supply of instrument air shall be provided. This allows controlled shutdown of

critical equipment when the instrument air system pressure drops to a level that threatens the activation of process shutdown devices.

- The air receiver sizing can be minimized by isolating nonessential air users from the air source on a predetermined low-pressure signal, thereby dedicating air storage to the critical air users.
- A single air receiver common to both instrument air and plant air systems is preferred. The economics of two receivers in large air systems shall be evaluated.

4.1.1.2. Supply to Critical Air Users

Where nonessential air users are isolated, care shall be taken to ensure that supply to critical plant air users is taken upstream of the automatic shutoff isolating valve.

4.1.2. Use of Portable Compressors

- Consideration shall be given to the use of supplemental portable compressors where high air demands exist for maintenance and plant turnaround.
- Lubricated, portable air compressors shall be provided with an oil filter when connected to the plant air system. The maximum remaining oil content in the air after filtration shall be 0.5 ppm by weight.
- Lubricated, portable air compressors shall never be connected to an instrument air system, either directly or indirectly.

4.1.3. Air Compressor Weather Protection

Air compressors shall be provided with a roofed shelter as minimum weather protection. An enclosed building shall be provided where extreme weather conditions are encountered.

4.2. Capacity

4.2.1. Instrument Air

The capacity of all components of an instrument air system shall be based on the total requirements of all connected loads using a 100 percent load factor.

- Table A–1 (Appendix A) lists air requirements for instruments, actuators associated with control or emergency devices and some purge connections.
- Air requirements for other users of instrument air, such as piston positioners, can be obtained from specific vendors' data.

- A minimum of 20 percent over capacity shall be included to cover air requirement adjustments after the compressor has been purchased.
- Final instrument air requirements shall be confirmed by the instruments and controls group.

4.2.2. Plant Air

The capacity of all components of a plant air system shall be based on the total requirements of all the continuous users plus the average air requirements of intermittent users.

- A minimum of 10 percent over-capacity shall be included to cover future requirements.
- Determination of the average air consumption is facilitated by the use of a load factor. Generally, pneumatic devices are operated only intermittently and often at less than full-load capacity. This number varies from plant to plant and is, at best, an estimate.
- Air tool requirements are given in Table A–2 and typical load factors for air tools are given in Table A–3.
- A sample calculation form that can be used to determine total plant air capacity is shown in Appendix B.

4.2.3. Load List

An itemized load list shall be prepared to determine the design requirements of the instruments for instrument air and plant air systems. This data shall be used to determine the capacity requirements of the air compressor(s).

The air compressor delivered-air requirements shall be expressed in Nm^3/h (scfm) at a reference temperature and pressure of 0°C and 101.325 kPa abs (60°F and 14.7 psia). The load list is subject to Mobil review.

4.2.4. Local Air Receivers

The installation of local air receivers shall be considered at the ends of long distribution lines or at intermediate points within the distribution system where intermittent air demands are high. Local air receivers could minimize excessive pressure drop and may permit the use of smaller compressors.

4.2.5. Air Leakage

System air leakage shall not be included for compressor sizing.

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4.3. Compressor Selection

4.3.1. Lubricated Compressors

Lubricated compressors, which introduce oil into the air compression chamber, are not recommended. Oil contamination of the air system and subsequent fouling of instruments makes lubricated compressors undesirable.

Where a lubricated compressor is still in service in existing plants, a coalescing-type, self-cleaning oil filter/separator shall be installed.

4.3.2. Discharge Pressure

The rated discharge pressure of instrument air and plant air compressors for most applications is nominally 862 kPa gauge (125 psig). This pressure is within the range of most pre-engineered air compressor packages and includes normal system pressure-drop losses.

4.3.3. Centrifugal Air Compressors

Oil-free centrifugal air compressors are best suited where demand is for high capacity with a minimum turndown ratio (see Figure 1). Pre-engineered compressor packages shall incorporate intercoolers, aftercoolers, moisture-removal equipment, lube-oil systems and controls of proven design.

Centrifugal air compressor packages can be supplied with either turbine or motor drives and shall comply with the requirements of MP 41-P-05.

4.3.4. Reciprocating Air Compressors

Oil-free reciprocating air compressors provide a considerable range of capacities and pressures. The use of oil-lubricated reciprocating compressors is not acceptable due to high operating temperatures and the danger of an explosion from an air/oil mixture.

Figure 2 illustrates a typical compressed air system design utilizing reciprocating air compressors. Multi-step unloading shall be considered where air demand is likely to vary considerably; that is, where there is a high load factor.

Because high discharge temperatures are developed, single-stage reciprocating machines are not recommended. Horizontally balanced opposed compressors are recommended and shall comply with the requirements of MP 41-P-06.

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4.3.5. Rotary Screw Air Compressors

Oil-free rotary screw air compressors are acceptable for air system applications. The mechanical specifications for proposed rotary screw compressors require review and approval by Mobil.

4.4. Intercoolers and Aftercoolers

Water-cooled coolers shall be of the shell-and-tube type and designed in accordance with TEMA C.

- The coolers shall utilize a water-through-tube design.
- The coolers shall be designed to cool the air to within 8°C (15°F) of the inlet water temperature, allowing for a fouling factor of 0.00035 $m^2 \bullet °C/W$ (0.002 $h \bullet ft^2 \bullet °F/Btu$) on the water side and 0.00018 $m^2 \bullet °C$ /W (0.001 $h \bullet ft^2 \bullet °F/Btu$) on the air side. If not otherwise specified, the water side pressure drop shall not exceed 70 kPa (10 psi) with a design velocity between 1.5 and 2.5 m/s (5 and 8 ft/s).
- Automatic moisture traps shall be provided for all intercoolers and aftercoolers. They shall be of proven design and provided with suitable freeze protection, if required.
- The amount of moisture remaining in saturated air after compression is shown in Figure 3.
- Air-cooled exchangers may be used when approved by Mobil.

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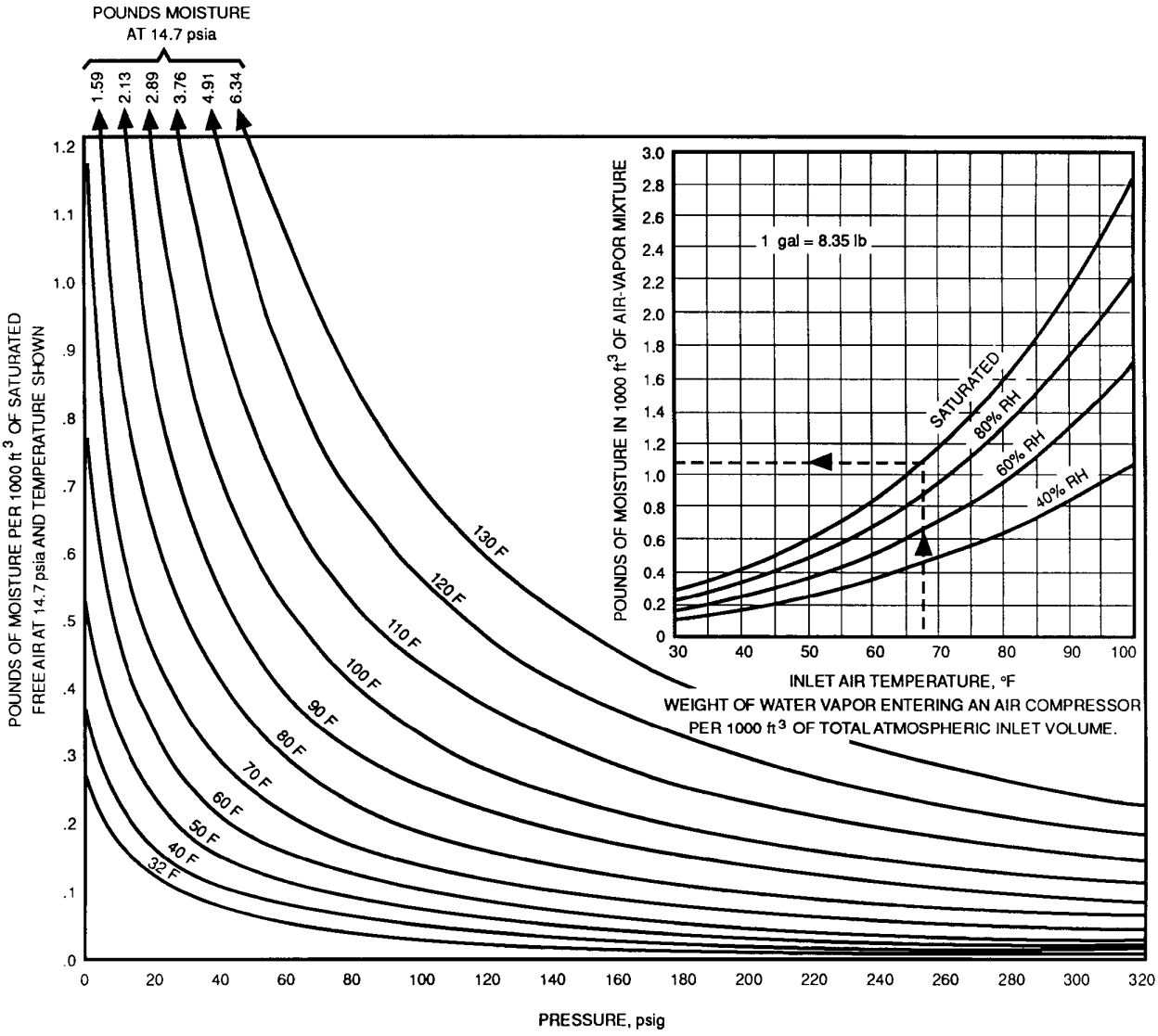

Figure 3: Amount of Moisture in Isothermally Compressed Air

4.5. Air Receivers

The capacity of air receivers shall be sufficient to provide adequate air supply to allow a controlled shutdown of critical systems and equipment on the total loss of instrument air supply. The receiver volume, V, required to provide adequate air supply without excessive pressure drop during the required time period, T, may be obtained from the following equation:

$$V = \frac{T \bullet C \bullet Pa}{(P_1 - P_2)}$$

Where:

V = Receiver capacity, in m^3 (ft^3).

T = Time required to allow logical and safe shutdown of critical systems and equipment, in minutes.

C = Total air requirements of all connected loads (continuous and intermittent) in the critical air system, in Nm^3/min (scfm). A 100 percent load factor is used, plus at least 20 percent margin for contingencies.

Pa = Atmospheric pressure, in kPa abs (psia).

P_1 = Receiver operating pressure at which nonessential air users are isolated from the compressed air source, in kPa gauge (psig)

P_2 = Receiver final pressure at which critical instrument air user emergency devices are activated, in kPa gauge (psig). This pressure level shall be determined by the instruments and controls group early in the design phase.

Each application will differ in requirements of time and capacity. Should the air receiver precede the establishment of the plant shutdown logic, it is suggested that the receiver be sized for the total requirements of the critical air system plus 20 percent margin for a period of at least five minutes. For reasons of economy, the receiver length-to-diameter ratio varies from 3 to 5.

4.5.1. Air Receiver Design

Air receivers shall be designed for a minimum pressure of 1.03 MPa gauge (150 psig). Receivers shall be of welded steel construction and shall conform to the requirements of ASME SEC VIII DIVISION 1 and MP 57-P-02. Standardized vessels that conform to the ASME Code and are manufactured on a production line basis may be used, provided prior Mobil approval is obtained.

As a minimum, the design of each receiver shall include the following:

1. Corrosion allowance of 2.5 mm (0.10 in).
2. Internal baffling or demisters to minimize carryover of entrained moisture. Demisters shall be readily removable for maintenance.
3. Automatic moisture trap, with suitable freeze protection when required.
4. Relief valve, complete with lifting lever. The valve shall be sized for fire conditions or blocked outlet, whichever governs. The formula to determine the required relieving area of safety valves for air in case of a fire is shown in Figure 4.

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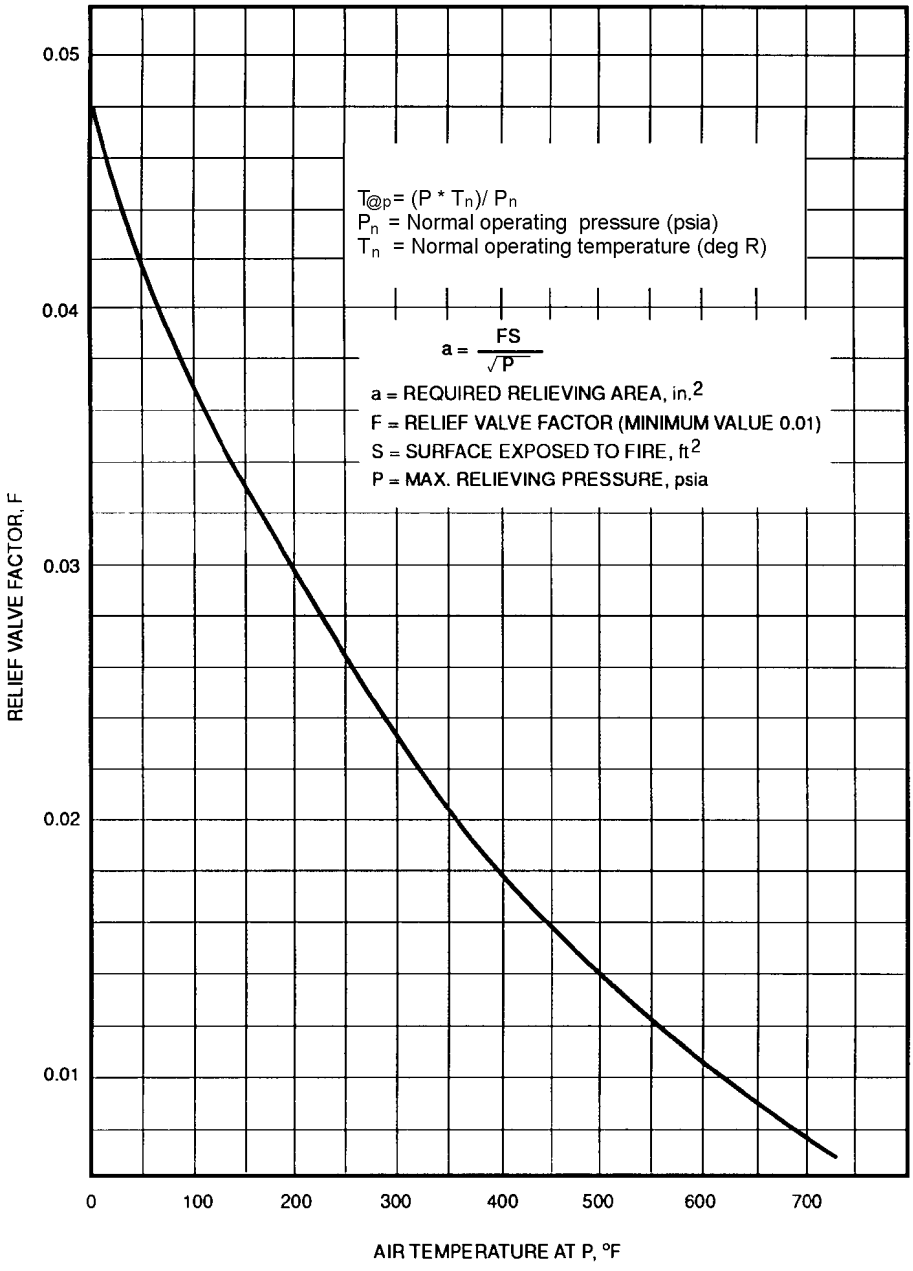

Figure 4: Safety Relief Valves–Air Expansion Service Due to Fire

4.6. Air Dryers

The drying of instrument air is essential to avoid:

- Corrosion of the system and the instruments
- Scaling, which can cause damage to instruments and plugging of small lines and nozzles

- Removal of lubricants from controllers
- Blockage and possible rupture of instruments and air lines in freezing climates

4.6.1. Pressure Dew Point Requirements

- The pressure dew point of the instrument air dryer shall be -40°C (-10°F) or at least 10°C (18°F) below the minimum ambient air temperature, whichever is the more stringent. The pressure dew point of -40°C (-10°F) is commonly accepted as a standard for instrument air and results in a moisture content of about 10 ppm.
- The drying of plant air is essential in freezing climates. The pressure dew point shall be maintained at least 10°C (18°F) below the minimum ambient temperature.
- Because of the drop in air temperature during pressure reduction through certain air-operated tools, it may be necessary to provide an air dryer to prevent excessive water precipitation, rapid tool wear or possible freezing. It may also be more economical in these cases to provide small local dryers. The pressure dew point shall be at least 10°C (18°F) below the minimum local recorded temperature at the plant site.

4.6.2. Types of Air Dryers

Commercially available compressed air dryers consist of three basic types:

1. Deliquescent (absorbent)
2. Regenerative desiccant (absorbent), including:
   a) Heat regenerated, either externally (convection) or internally (conduction and convection)
   b) Heatless regenerated (pressure swing)
3. Refrigerant–includes the chilling type

4.6.2.1. Deliquescent Air Dryers

The deliquescent type of air dryer shall not be used for drying instrument air because liquids can be carried into the system and damage instrumentation. This type of dryer uses beads or pellets of material that absorb moisture from the air it contacts. The material turns into a liquid as the water vapor is absorbed. This liquid shall be drained off and the beads replaced periodically.

Deliquescent air dryers can attain a pressure dew point of 2–10°C (35–50°F).

4.6.2.2. Regenerative Desiccant Air Dryers

The regenerative type of desiccant air dryer is recommended for drying instrument air. This dryer uses materials that adsorb the water vapor from

the air. The material is a solid at all times and operates alternately through drying and regeneration cycles with no change in composition.

The desiccants usually provided in regenerative air dryers are activated alumina, silica gel, and to a lesser extent, molecular sieve.

- The structure of silica gel can be destroyed by the intrusion of liquid water. An activated alumina or molecular sieve buffer bed of at least 150 mm (6 inches) depth is required at the air inlet end of a silica gel desiccant bed to protect against such damage. Silica gel can also be damaged by high temperatures and shall not be exposed to the high wall temperatures of internal electric heating elements.

- No single desiccant is suitable for all applications. Thus, desiccant selection shall be made on the basis of operating parameters such as regeneration method and maximum temperature.

4.6.2.2.1. Heatless Dryers

The regeneration cycle for a heatless dryer consists of diverting a portion of the dried air through a reducing valve or orifice, reducing its pressure to atmospheric and passing it through the wet desiccant bed. This air, with the moisture it has picked up, is vented to atmosphere. The air diverted may vary between 7 and 17 percent of the main stream flow, depending on the final dew point required.

Since the heatless dryer uses such a large percentage of the main stream flow for regeneration, an economic evaluation shall be conducted to determine the most cost-effective system. The evaluation shall include dryer cost comparisons specified in MP 41-P-10 and the increased compressor system cost (installed and operating).

4.6.2.2.2. Heat-Regenerated Dryers

Heat-regenerated dryers heat the activating air prior to its passing through the bed or heat the bed itself. This requires less diverting air since each cubic foot will carry more moisture out of the system. A pressure dew point as low as -73°C (-100°F) can be obtained.

4.6.2.2.3. Dual-Tower Regenerative Dryers

Dual-tower regenerative dryers shall be furnished for plant air and instrument air systems. The mechanical design requirements for regenerative air dryers shall be in accordance with MP 41-P-10.

- When an uninterruptible air supply is required, it is standard practice to provide two 100 percent capacity dual-tower dryers to guarantee instrument air supply.

- An automatic dryer bypass shall be provided for single-dryer applications. The bypass valve is activated from a low-flow signal received from flow elements located on the dryer outlet header.

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- An oil-removal prefilter with continuous drainers and pressure differential indicators shall be installed upstream of the dryer.
- A 3 micron afterfilter with a pressure differential indicator shall be installed downstream to trap desiccant carryover. The afterfilter can be simple cartridge type.
- Both filters shall be provided with block and bypass valves to permit servicing of the filter media without a complete shutdown.
- A typical system of this type is shown in Figure 5.

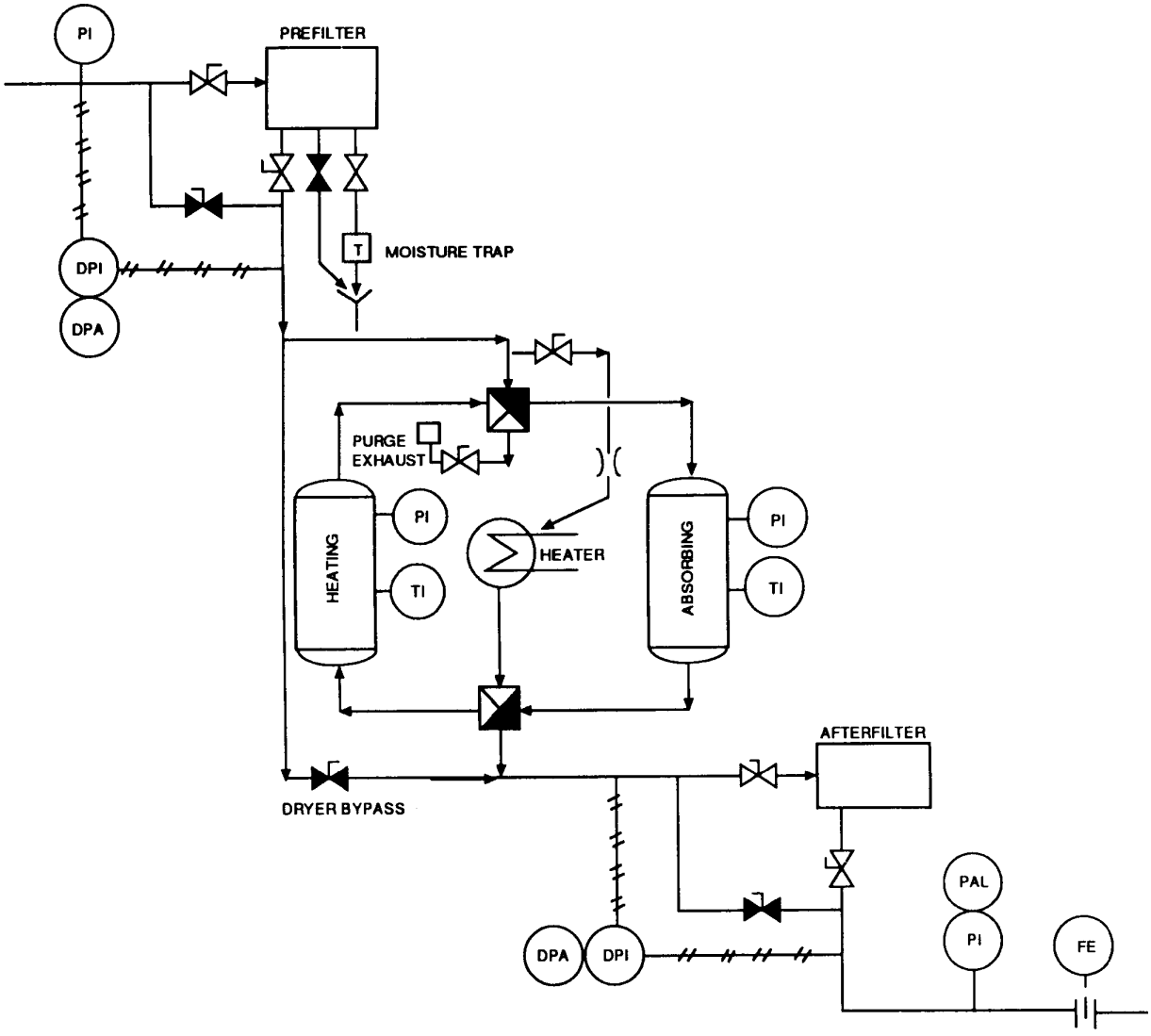

Figure 5: Typical Air Dryer

NOTE: Instrument control system is typical. Dryer depicted is the adsorbent desiccant type with external heat regeneration.

4.6.2.3. Refrigerant Air Dryers

- Two methods are available with the refrigerant type of air dryer:
  - Flow of air through directly refrigerated coils is used predominantly in smaller and moderate-sized systems. These are generally standardized for cooling to a pressure dew point of 3°C (38°F).
  - The larger systems chill water that is circulated through coils to cool the air. A pressure dew point of about 10°C (50°F) is obtainable by this method.
- In both of these methods, the drying operation is interrupted on power failure.
- Neither method is recommended for drying instrument air since the quality standard for instrument air, as seated in ISA S7.3, cannot be obtained.
- Refrigerant air dryers shall be located indoors.

4.6.3. Combination Dryers

Combination dryers can be used when very low-pressure dew points are required. Placing a refrigerant system ahead of a regenerative dryer will let the more-economical refrigerant system remove most of the water vapor and reduce the load on the desiccant. The overall economics of this arrangement shall be considered.

4.6.4. Dryer Type Advantages/Disadvantages

Table 1 lists some general advantages and disadvantages of the various types of air dryers.

Table 1: Types of Dryers

Deliquescent	**Regenerative Desiccant**	**Refrigerant**
Advantages:		
Low initial cost	Low dew points to -73°C (-100°F)	Constant dew point
Simplicity		Low operating costs
No moving parts		No damage by oil vapors or aerosois
Disadvantages:		
Limited dew point suppression	High initial cost	Dew points below3°C (38°F) not possible
Periodic replacement of desiccant	High operating costs	Subject to high maintenance in corrosive atmosphere

Deliquescent	Regenerative Desiccant	Refrigerant
High maintenance (because most automatic drains will not handle deliquescent solution, the liquid shall be drained manually at least once a day)	Periodic servicing of desiccant towers	Susceptible to freezing
	Vulnerable to coating of desiccant by oil aerosois, rendering it useless	
Some deliquescent materials melt or fuse together at temperatures as low as 32°C (90°F) (this caking or channeling renders them useless–wet air can flow through without reacting with the desiccant)		
Possible corrosion by liquid		

4.7. Plant Air and Instrument Air Distribution Systems

Piping, flanges and fittings shall conform to the requirements of ASME B31.3 and ASME B16.5. All welding shall meet the requirements of MP 57-P-02.

4.7.1. Corrosion Allowances

Carbon steel piping and equipment shall have a minimum corrosion allowance of 1.2 mm (0.05 inches). In areas of piping and equipment where water is condensing or accumulating, the minimum corrosion allowance for carbon steel shall be 2.5 mm (0.10 inches).

4.7.2. Loop Systems

Yard and Instrument Air header systems shall be designed to facilitate maintenance and/or isolation without disruption of service to individual units.

The use of a loop system (around the plant and within each area and building) is preferred. This arrangement provides two-way air distribution and, when properly designed with adequate block valves, enables sections of the piping system to be isolated for maintenance.

The main piping of the loop system shall be sized so that the total air requirement can be supplied from either direction without excessive pressure drop.

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4.7.3. Pipe Sizing

- Piping shall normally be sized so that the pressure drop between a receiver and the farthest point of use does not exceed 10 percent of the compressor discharge pressure (see Figure 6).

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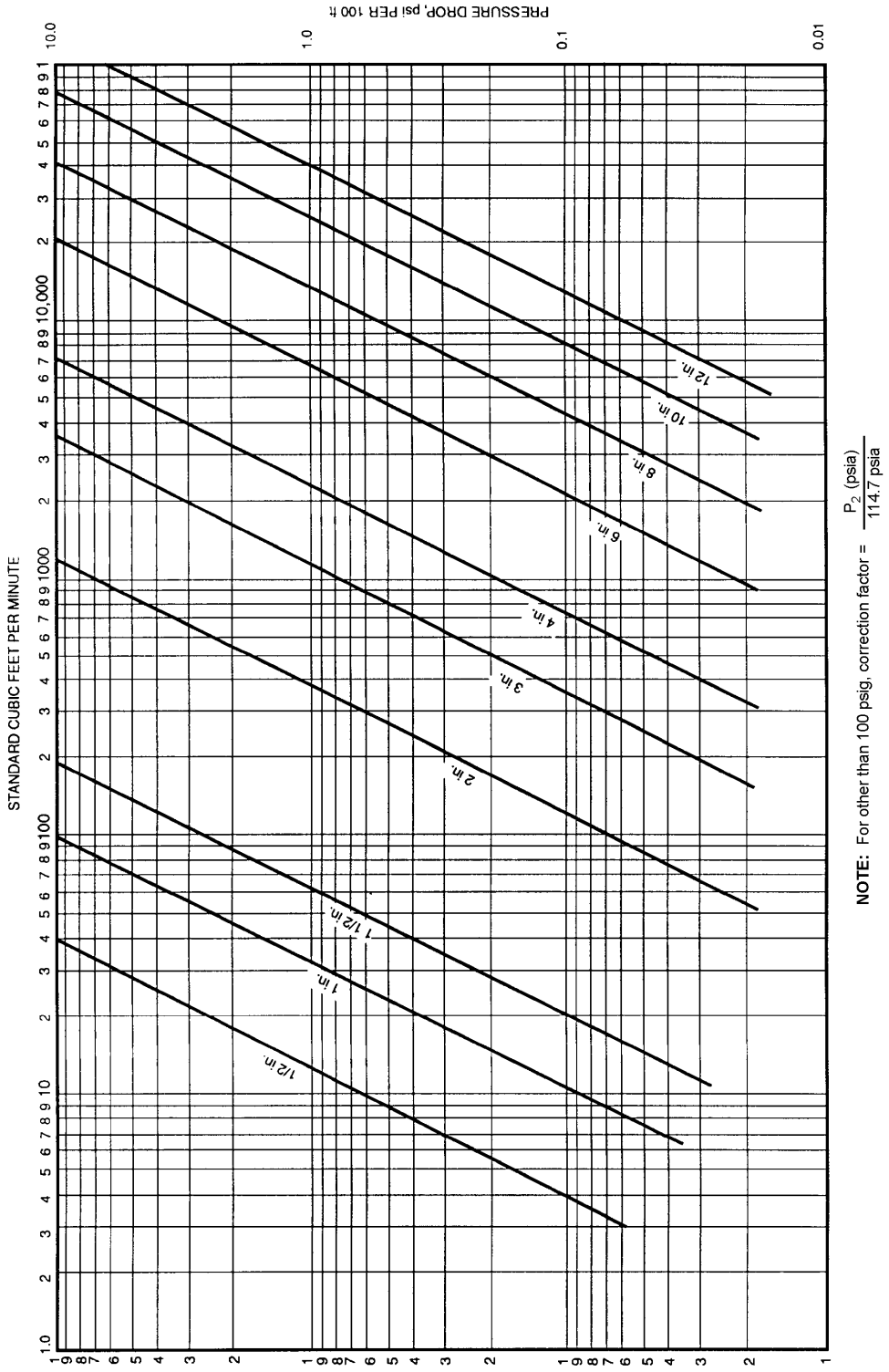

Figure 6: Loss of Air Pressure Due to Friction per 100 ft of Pipe and 100 psig Initial Pressure

4.7.4. Condensation Considerations

- Each plant air and/or instrument air header (or main) shall be provided with branch connections as close as possible to the air users. It is recommended that branch connections be provided with block valves and be taken from the top of the pipe or header to prevent carryover of condensed moisture.
- Ideally, all plant air and instrument air piping shall be sloped to drain toward a drip leg and air trap in order to remove condensation. To prevent backflow, the lines shall slope away from the compressor. (It shall be noted that this arrangement is not possible in intercooler piping).
- Plant air system piping shall be provided with drip legs at not more than 60 m (200 ft) spacing. In freezing climates, drip legs, drains and air traps shall be heat traced.

4.7.5. Compressor Piping

- Air compressor suction piping between the filter/silencer and compressor connection shall be either epoxy-coated steel, hot-dip galvanized steel or stainless steel. Other permanent, corrosion-resistant materials may be used if approved by Mobil. A suction line valve (usually, a butterfly valve) shall be provided as part of the compressor package for startup and control purposes on all centrifugal air compressors.
- Compressor discharge piping upstream of the aftercooler shall be installed with a minimum number of bends and lengths of piping. Moisture separators may be detached from the aftercooler to improve the piping arrangement. However, only one elbow or bend shall be installed between the cooler and separator.

4.7.6. Sight Flow Indicators

Sight flow indicators shall be provided on the return legs of all cooling water connections unless the water is being discharged to an open sewer hub. These connections include intercoolers, aftercoolers, oil coolers and jacket water cooling.

4.8. Controls and Instrumentation

Local compressor control may be of the electronic, electrical or pneumatic type. However, any control transmission to a central control house shall be electronic/electrical.

Control systems shall be backed up by reliable standby sources of power and/or dry air.

Controls and instrumentation shall conform to MP 41-P-06, MP 41-P-05, MP 32-P-01 and relevant Practices listed therein.

Standby compressors shall be provided with automatic startup systems.

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Normally, capacity control for reciprocating air compressors is accomplished with suction valve unloaders. Capacity control for centrifugal compressors shall be in accordance with MP 41-P-05.

A moisture monitor with alarm shall be provided on the main outlet line from the instrument air dryer. Low-pressure alarms, wired to the appropriate control room or plant distributed control system, shall be fitted on the main instrument air headers in each unit or major utility.

4.9. Cooling Water Requirements

Normally, water for cooling air compressor accessories is supplied from a recirculated cooling water system. Closed-loop cylinder cooling systems for reciprocating compressors shall be provided in accordance with MP 41-P-06.

Preliminary cooling water requirements for air compressors can be obtained as follows:

Reciprocating Type:

Less than 645 Nm^3/h (400 scfm) air:

2.3 m^3/h per 160 Nm^3/h (10 US gpm/100 scfm) air

645 Nm^3/h (400 scfm) and greater air:

1.8 m^3/h per 160 Nm^3/h (8 US gpm/100 scfm) air

Centrifugal Type:

2.3 m^3/h per 160 Nm^3/h (10 US gpm/100 scfm) air

The results are estimates and shall be confirmed during definitive design of the cool water system by the selected air compressor vendor. The estimates are based on industry standards of an 8°C (15°F) approach for aftercooler design.

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Appendix A: Air Requirements

Table A–1: Instrument Air Requirements

Bleed-type instruments	0.80 Nm3/h (0.5 scfm)			
Pneumatic cylinders	Varies with piston diameter and stroke, 4.8 to 16 Nm^3/h (3 to 10 scfm)			
Instrument purge	Varies with orifice size. At a pressure of 310 kPa gauge (45 psig), the air consumption is as follows:			
	Orifice Size		**Air Consumption**	
	mm	**In**	**Nm3/h**	**scfm**
	1.6	$^1/_{16}$	5.4	3.38
	3.2	$^1/_8$	21.7	13.50
	6.4	$^1/_4$	87.0	54.10
	9.5	$^3/_8$	196.0	122.00
Pneumatic instrument valve actuators	1.6 to 8.0 Nm^3/h (1 to 5 scfm)			

Table A–2: Pneumatic Tools: Plant Air Consumption in Quantities of Free Air*

Air Motors						
kW	1.5	3	3.7	6	11.2	
m^3/h	68-85	110	161	212	408	
Hp	2	4	5	8	15	
cfm	40-50	65	95	125	240	
Hand Riveters						
Size, kg	5.9	6.6	7.5	8.9	9.8	10.9
m^3/h	27	31	34	37	40	42
Size, lb	13	14.5	16.5	19.5	21.5	24
cfm	16	18	20	22	24	25
Chipping Hammers						
Weight, kg	2.3	3.6	4.5	5.4	6.4	8.2

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m^3/h	10	20	25	31	34	37
Weight, lb	5	8	10	12	14	18
cfm	6	12	15	18	20	22
Steel Drills (Rotary)						
Size, mm	To 6.4	6.4-9.5	12.7-19	22.2-25.4	31.8	
m^3/h	31-34	34-68	119	136	161	
Size, inches	To $^1/_4$	$^1/_4 - ^3/_8$	$^1/_2$ - $^3/_4$	$^7/_8 - 1$	$1\ ^1/_4$	
cfm	18-20	20-40	70	80	95	
Steel Drills (Piston)						
Size, mm	12.7-19	22.2-31.8	31.8-50.8	50.8-76.2		
m^3/h	76	127-136	136-153	170-187		
Size, inches	$^1/_2 - ^3/_4$	$^7/_8 - 1\ ^1/_4$	$1\ ^1/_4 - 2$	2-3		
cfm	45	75-80	80-90	100-110		
Wood Borers						
Size, mm	To 25.4	50.8				
m^3/h	68	136				
Size, inches	To 1	2				
cfm	40	80				
Sandblasters						
Nozzle size, mm	4.8	6.4	9.5	12.7		
Kg sand/h	227	408	771	1361		
m^3/h	90	156	360	639		
Nozzle size, inches	$^3/_{16}$	$^1/_4$	$^3/_8$	$^1/_2$		
Lb sand/h	500	900	1700	3000		
cfm	53	92	212	376		
Pile Hammers						
Weight, kg	65.8	290	680	2268	3400	
m^3/h	170	255	340	595	1020	
Size, inches	145	640	1500	5000	7500	
cfm	100	150	200	350	600	
Geared Hoists						
Capacity, tonnes	1.8	3.6	5.4	7.3	9.?	

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$m^3/h/m$ of lift	33	56	111	139	167	
Capacity, tons	2	4	6	8	10	
cfm/ft of lift	6	10	20	25	30	
Grinders						
Size, mm	100	200				
m^3/h	59	85				
Size, inches	4	8				
cfm	35	50				
Paint sprayers	Small, 3.4 to 25 m^3/h (2 to 15 cfm)					
Screwdrivers	Small, 17 m^3/h (10 cfm); large 51 m^3/h (30 cfm)					
Nut setters	Small, 34 m^3/h (20 cfm); large, 51 m^3/h (30 cfm)					
Furnace tube cleaners	76 to 425 m^3/h (45 to 250 cfm), depending on size					
Bung wrenches	17 m^3/h (10 cfm)					
Drum sealing tools	17 m^3/h (10 cfm)					

*620 kPa (90 psig) at tool

Table A–3: Typical Tool Load Factor

Tool	**Factor***
Grinder	0.5-0.8
Chipper	0.5
Hoist	0.1-0.3
Screwdriver	0.25-0.5
Nut Setter	0.25-0.5
Wood Borer	0.25
Rotary Drill	0.2-0.5
Riveter	0.5-1.0
Sandblaster	0.2-1.0
Paint Sprayer	0.2-1.0
Motor	0.2-1.0

* Factors may vary appreciably among locations, depending upon age and condition of tools and frequency of use.

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Table A–4: Typical Unit Air Requirements (Based on Joliet Refinery Data)

	Plant Air				Instrument Air			
Facility	**Nm3/h**		**scfm**		**Nm3/h**		**scfm**	
	Normal	**Max**	**Normal**	**Max**	**Normal**	**Max**	**Normal**	**Max**
Crude unit	0	80	0	50	322	402	200	250
FCC unit	241	1383	150	860	322	563	200	350
Alkylation	177	177	110	110	241	322	150	200
CHD	0	160	0	100	241	362	150	225
Saturated gas	40	40	25	25	241	322	150	200
Unsaturated gas	0	160	0	100	241	322	150	200
Pretreater and PtR	0	80	0	50	120	160	75	100
Coker	1608	1930	1000*	1200*	160	241	100	150
Sulfur plant and amine unit	0	80	0	50	80	120	50	75
Gasoline treating	0	80	0	50	80	120	50	75
Tankage, blending, movement	80	160	50	100	200	241	125	150
Utility plant	0	160	0	100	322	482	200	300
Waste disposal	0	80	0	50	80	120	50	75
Total	**2145**	**4570**	**1335**	**2845**	**2650**	**3780**	**1650**	**2350**

Regeneration air requirements:

- PtR (24 hours, semiannually): 4825 Nm^3/h (3000 scfm) for a 10,900 tonnes/day (40,000 BPSD) unit (Note 1)
- CHD (24 hours, annually): 9070 Nm^3/h (5642 scfm) for a 14,450 tonnes/day (53,000 BPSD) unit (Note 2)

NOTES:

*Includes hydraulic coke cutters and air tools used on drums: 2/24 hours.

1. Based on 58 Nm^3/h per 1608 Nm^3/h (36 scfm per 1000 scfm) of reformer nitrogen cycle.
2. Based on volume of catalyst (see Figure A–1).

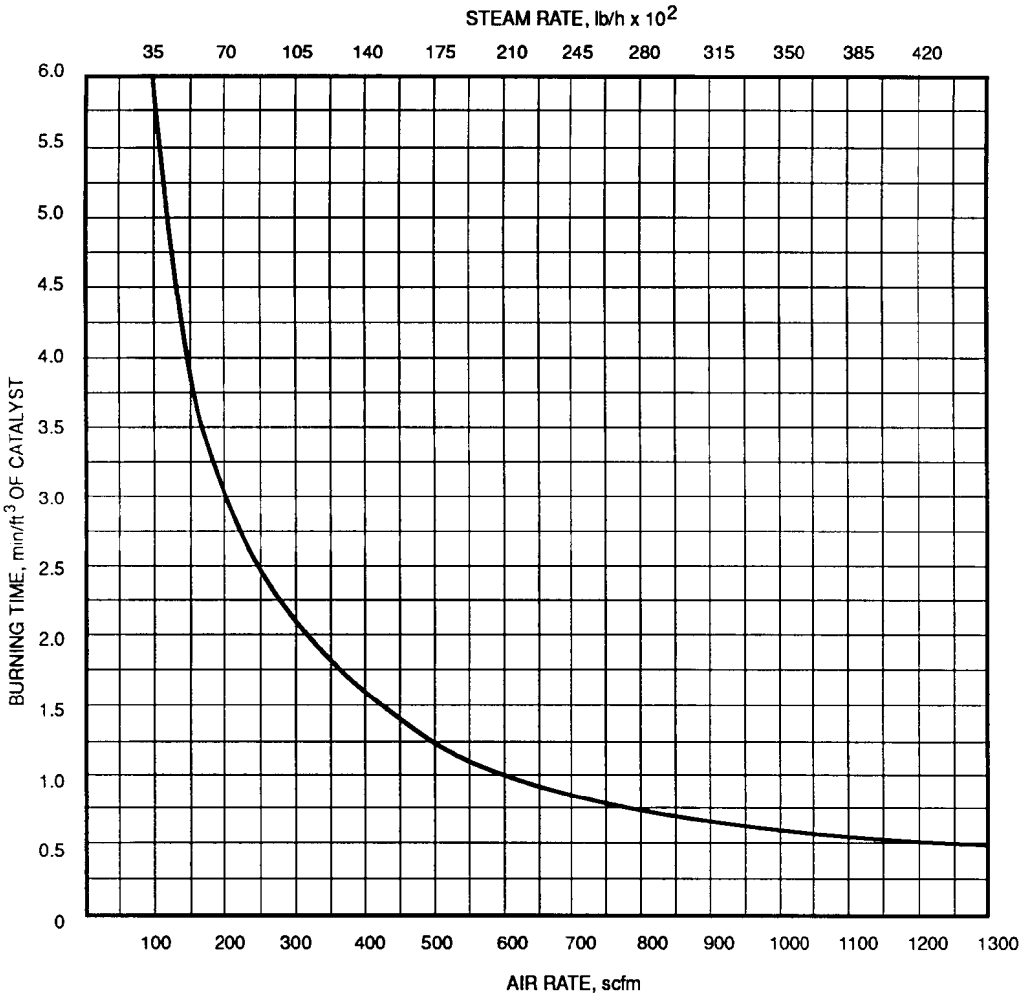

Figure A–1: CHD Regeneration

NOTES TO FIGURE A–1:

1. Curve based on 7.5 mol air in air system mixture
2. Curve based on 42 lb/ft^3 catalyst density, 8 percent coke and 5 percent sulfur

Appendix B: Plant Air Planning Sheet

		1	2	3	4	5
Item Description	**Department Location**	**Quantity (No. of Devices)**	**Unit Consumption Nm^3/h (scfm)**	**Total Consumption Nm^3/h (scfm) (1 x 2)**	**Load Factor (Individually)**	**Adjusted Consumption Nm^3/h (scfm) (3 x 4)**

Automatic Tank Gauging

EPT 15-T-16

August 1998 Draft

Scope

This Mobil Engineering Practice Tutorial (EPT) defines design criteria, system requirements and Mobil Engineering Practices (MEPS) for designing automatic tank gauging (ATG) systems for aboveground and underground storage tanks. This EPT does not include gauging of marine vessels and manual gauging methods.

The purpose of this EPT is to present considerations and criteria necessary for the selection of automatic tank gauging systems for aboveground and underground tanks and to provide information on the secondary uses of automatic tank gauging systems.

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Table of Contents

Scope **1**

Table of Figures **5**

1. References **6**

1.1. MEPS–Mobil Engineering Practices 6

1.2. Mobil Data Sheets 6

1.3. Mobil Tutorials 6

2. Definitions **7**

3. System Description–Aboveground Tanks **7**

3.1. General 7

3.2. Hydrostatic Tank Gauging (HTG) System 8

3.3. Servo Gauging System 9

3.4. Radar Gauging System 13

3.5. Magnetostrictive Gauging System 15

3.6. Bubbler Gauging System 18

3.7. Float and Tape Gauging System 20

4. Considerations and Criteria **22**

4.1. Objectives of Automatic Tank Gauging 22

4.2. ATG System Selection 23

4.3. Site Survey 23

4.4. Operating Practices 24

4.5. Related Facilities 24

5. System Design–Aboveground Tanks **25**

5.1. General 25

5.2. System Layout 25

5.3. System Software and Communication Protocol 35

5.4. Integration with Other Systems 37

6. System Description–Underground Tanks 38

6.1. General 38

6.2. Two ATG Systems 38

7. Considerations, Criteria and System Design–Underground Tanks 42

7.1. Objectives of Automatic Tank Gauging 42

7.2. System Selection 43

7.3. System Design 43

8. System Testing, Calibration, Startup and Training–Aboveground and Underground Tanks 45

8.1. Accuracy Verification 45

8.2. Training 45

Appendix A: Systems Comparison–Aboveground Tanks 47

Appendix B: System Requirements Tank Data–Aboveground and Underground Storage Tanks 51

Appendix C: Leak Detection Procedure with HTG System 53

1. General 53

2. Mass Deviation Set Point 53

3. Inputting Mass Deviation Alarm Set Point 54

4. Performing On-line Leak Detection 54

Appendix D: Integration with High Level Alarm Systems 56

1. General 56

2. System Integration 56

2.1. High Level Condition or High-High (Noninterlocking Function) 56

2.2. High/High Level Condition (Interlocking Function) 57

Table of Figures

Figure 1: HTG System Schematic 8

Figure 2: Servo Gauging System 10

Figure 3: Servo Gauging System Schematic 11

Figure 4: Hybrid System Schematic 13

Figure 5: Radar Gauging System 14

Figure 6: Magnetostrictive Gauging System 16

Figure 7: Magnetostrictive Gauging System Schematic 17

Figure 8: Bubbler Gauging System Schematic 19

Figure 9: Float and Tape Gauging System Schematic 21

Figure 10: Typical Layout and Dimensions 27

Figure 11: Storage Tanks–Location of Shell and Bottom Connections and Appurtenances 29

Figure 12: Storage Tanks–Location of Roof Connections and Appurtenances 30

Figure 13: Storage Tanks–Gauging Datum Plate 32

Figure 14: Storage Tanks: Ground Reading Averaging Thermometer 33

Figure 15: Aboveground Tank System 35

Figure 16: Magnetostrictive Gauging System Schematic 39

Figure 17: Ultrasonic Tank Gauging System Schematic 41

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1. References

The following publications form a part of this Practice. Unless otherwise specified herein, use the latest edition.

1.1. MEPS–Mobil Engineering Practices

MP 00-P-04	Winterizing & Heat Tracing
MP 32-P-22	Storage Tank Inventory Instrumentation
MP 33-P-11	Electrical - Secondary-Selective Systems
MP 34-P-10	Thermal Insulation - Hot Service

1.2. Mobil Data Sheets

Mobil Data Sheets	Mobil Data Sheet Home Page
T1401C01	Aboveground Welded Steel Storage Tanks - Design & Construction - Customary Units
T1401M01	Aboveground Welded Steel Storage Tanks - Design & Construction - Metric Units
T1401C02	Aboveground Welded Steel Storage Tanks - Design & Construction - Customary Units
T1401M02	Aboveground Welded Steel Storage Tanks - Design & Construction - Metric Units
D1401C01	Aboveground Welded Steel Storage Tanks - Design & Construction - Documentation Requirements Sheet

1.3. Mobil Tutorials

EPT 15-T-18A	Electrical Design for Marketing Plants
EPT 15-T-18B	Electrical Design for Marketing Plants

2. Definitions

Datum	Base point of reference. In the case of servo-driven displacer type gauges, the ullage datum plane is usually in the form of a fixed plate mounted inside the gauge head support assembly for atmospheric tanks. For pressurized tanks, the datum plane is the top of the ball of the ball valve upon which the gauge head (transmitter) is mounted. The innage datum is usually in the form of a plate mounted at the bottom of the stilling well in which the displacer is suspended.
Mobil Approval	This term shall mean "written" approval.
Innage	The volume of the liquid contents of the tank, calculated by measurement from a fixed datum plane above the tank bottom plate to the liquid surface.
Reference Height	The distance between the bottom datum and the top reference point of the gauging system.
Reference Point	A point from which ullage is measured.
Ullage	The volume of space above the liquid surface, calculated by measurement from the top datum plane (ullage dip reference) to the liquid surface.

3. System Description–Aboveground Tanks

3.1. General

Automatic tank gauging (ATG) system components consist of:

- A level or a pressure sensor (a float, a displacer, hydrostatic diaphragm, etc.)
- Mechanical/electronic transmitters
- A local tankside level indicator (recommended option)
- A receiver-decoder and display device, usually a CRT
- A printer may also be provided

A resistance temperature device (RTD) single probe must be incorporated into the ATG system for determination of volume at 15°C (60°F). Also, API volume correction factors for each product stored need to be included in the software. An averaging temperature probe shall be included for tanks greater than 30 m (100 ft) in diameter where temperature stratification is anticipated.

Incorporation of leak detection capability shall be considered when selecting ATG.

MP 32-P-22 contains the minimum requirements for level gauging equipment. It shows the details of pressure transmitter mounting, stilling wells and other necessary items.

Because of varying technologies, several automatic tank gauging systems are in widespread use within the petroleum industry. These systems are described herein along with their relative advantages and disadvantages, which are summarized in Appendix A, Table A–1 of this Tutorial.

3.2. Hydrostatic Tank Gauging (HTG) System

HTG systems use pressure sensors and transmitters to measure product mass and to calculate product density, level and volume in a storage tank. They provide superior accuracy on mass basis at a reasonable cost. A system schematic is presented in Figure 1.

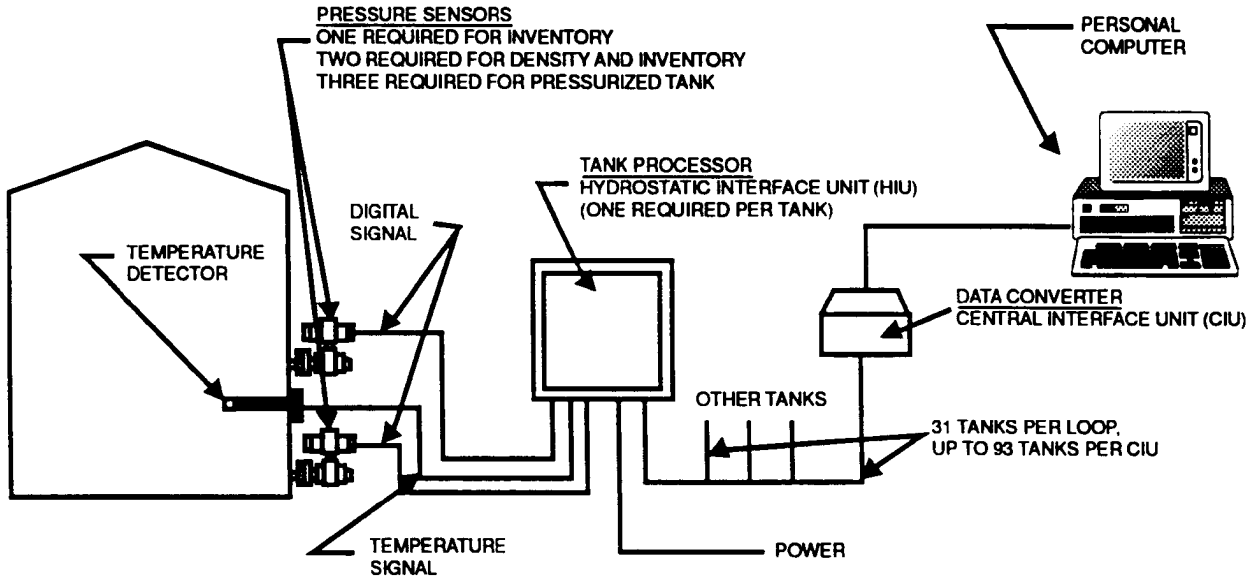

Figure 1: HTG System Schematic

3.2.1. Advantages

- Superior mass-based accuracy.
- Low installation cost.
- Low maintenance cost since the tank has no moving parts.
- Leak detection capability (see Appendix C).
- Provides real time, accurate density when both HTG pressure sensors are covered and product has uniform density.

- Capable of detecting water interface when supplemented with a capacitance-type probe.
- Mass calculations are not affected by stratification and temperature effect because the mass is calculated on the basis of accurate measurement of hydrostatic pressure and cross-sectional area of the tank at that point.
- Recommended for automated process operations involving mass flow requirements. Thus, it is particularly suitable for batch blending processes.
- Accuracy is not adversely affected by movement of the reference point because the sensors are not mounted on the tank roof.

3.2.2. Disadvantages

- Product stratification affects the accuracy of the measured density and, therefore, the volume and level accuracy. This is because observed density is used to calculate volume and level.
- When the upper probe (see Figure 1) is uncovered, the level is calculated on the last observed density. If product is received in the tank so that this probe remains uncovered, the calculated volume and level may not be accurate if the density of the product received is different from that of product in the tank. This problem can be minimized if the operator samples the product and inputs the laboratory-observed density through the system software.

3.3. Servo Gauging System

Servo gauging systems use a static force transducer, which continuously measures the tension in a wire that suspends a compact solid displacer. This wire is stored in a small precision grooved drum. The tension when the displacer is slightly immersed in the liquid is the equilibrium tension (see Figure 2).

- A small change in the liquid level causes a corresponding change in the weight of the displacer and the tension of the wire. This tension change energizes a positioner (servo) that drives the wire drum controlling the displacer upward or downward as product rises or falls. As soon as equilibrium tension is re-established, the servo shuts off.
- Liquid level oscillation effects are minimized by setting a programmable timer that delays the action of the positioner. This allows accurate measurement of turbulent liquids and eliminates unnecessary wear and tear on the instrument.
- Interface (product/water) detection can be programmed into the system. The transducer detects a change in tension caused by the displacer being partially immersed in both liquids. The system also allows precise measurement of the displacer weight, allowing product density measurement at any level.

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- It is recommended that servo gauging systems be installed on a stilling well with hinged datum plate to permit axial movement of the stilling well pipe to avoid erroneous results (see MP 32-P-22 for details). A system schematic is presented in Figure 3.

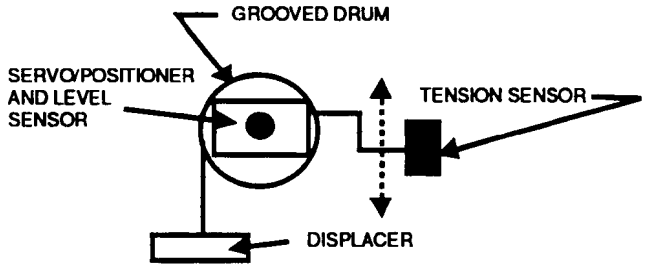

Figure 2: Servo Gauging System

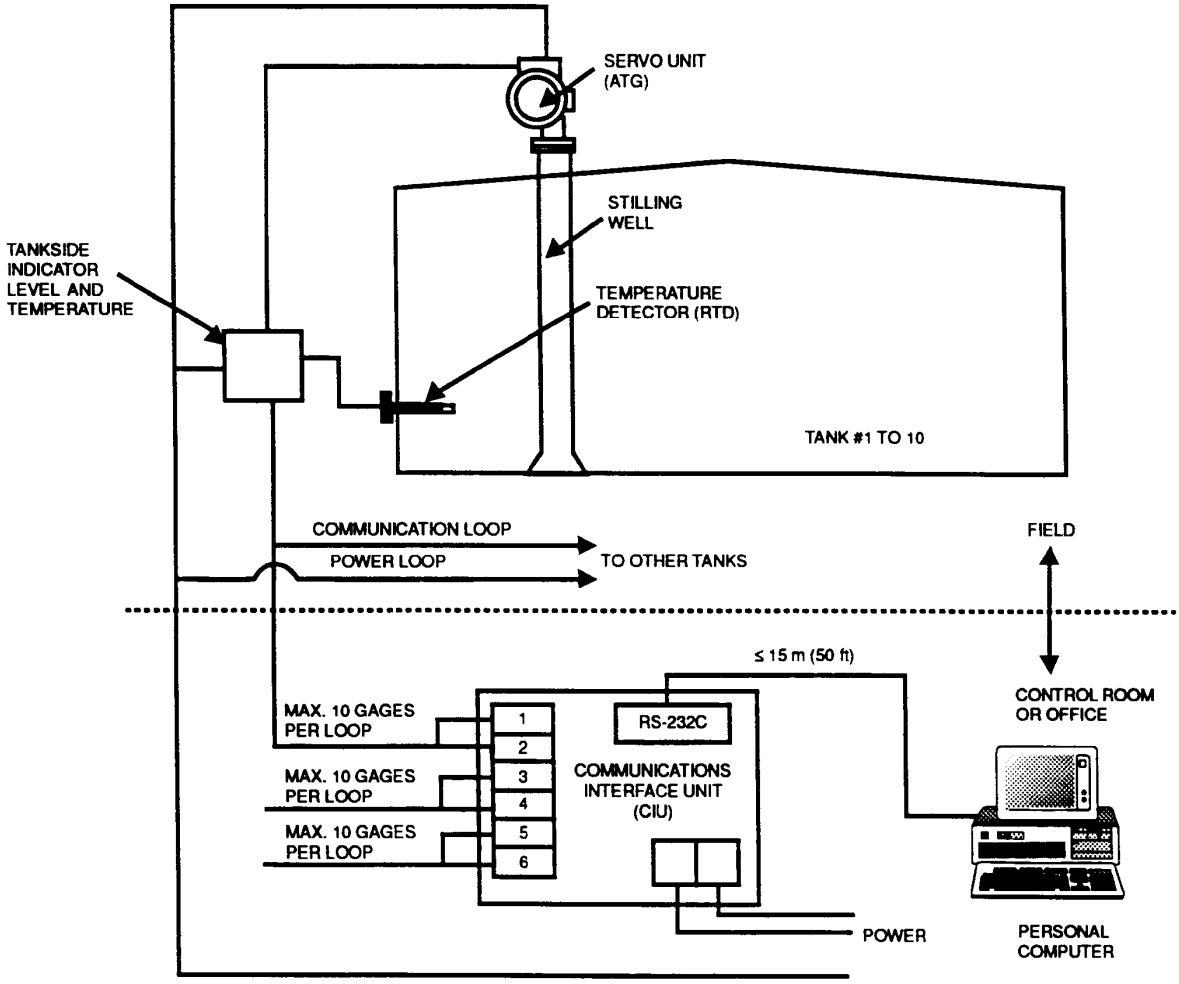

Figure 3: Servo Gauging System Schematic

3.3.1. Advantages

- Superior level accuracy when installed with a stilling well.
- Low maintenance cost (requires verification of calibration every two years).
- Capable of detecting water interface (when programmed).
- Level accuracy is not affected by product stratification in the tank.
- Can be used in automated process operations that depend on volume flow.
- When provided with an averaging temperature probe, the servo gauging system has limited leak detection capability based on standard volume at 15°C (60°F).

3.3.2. Disadvantages

- Manual (operator) input of density to calculate mass limits the calculation accuracy.
- Because it is roof mounted and measures ullage, the system could give erroneous results if the reference point moves due to flexing of the tank bottom, shell or roof.
- Tanks greater than 30 m (100 ft) in diameter and tanks with temperature stratification require an averaging temperature probe to calculate volume at a temperature of 15°C (60°F).

3.3.3. Hybrid Arrangement

If this system is fitted with a hydrostatic gauge and transmitter, it can provide accurate real time mass, level and density measurements. This arrangement, classified as "Hybrid," combines the advantages of both the servo and HTG systems. The cost of the hybrid system is higher than a nonhybrid system. A schematic of the hybrid system is shown in Figure 4.

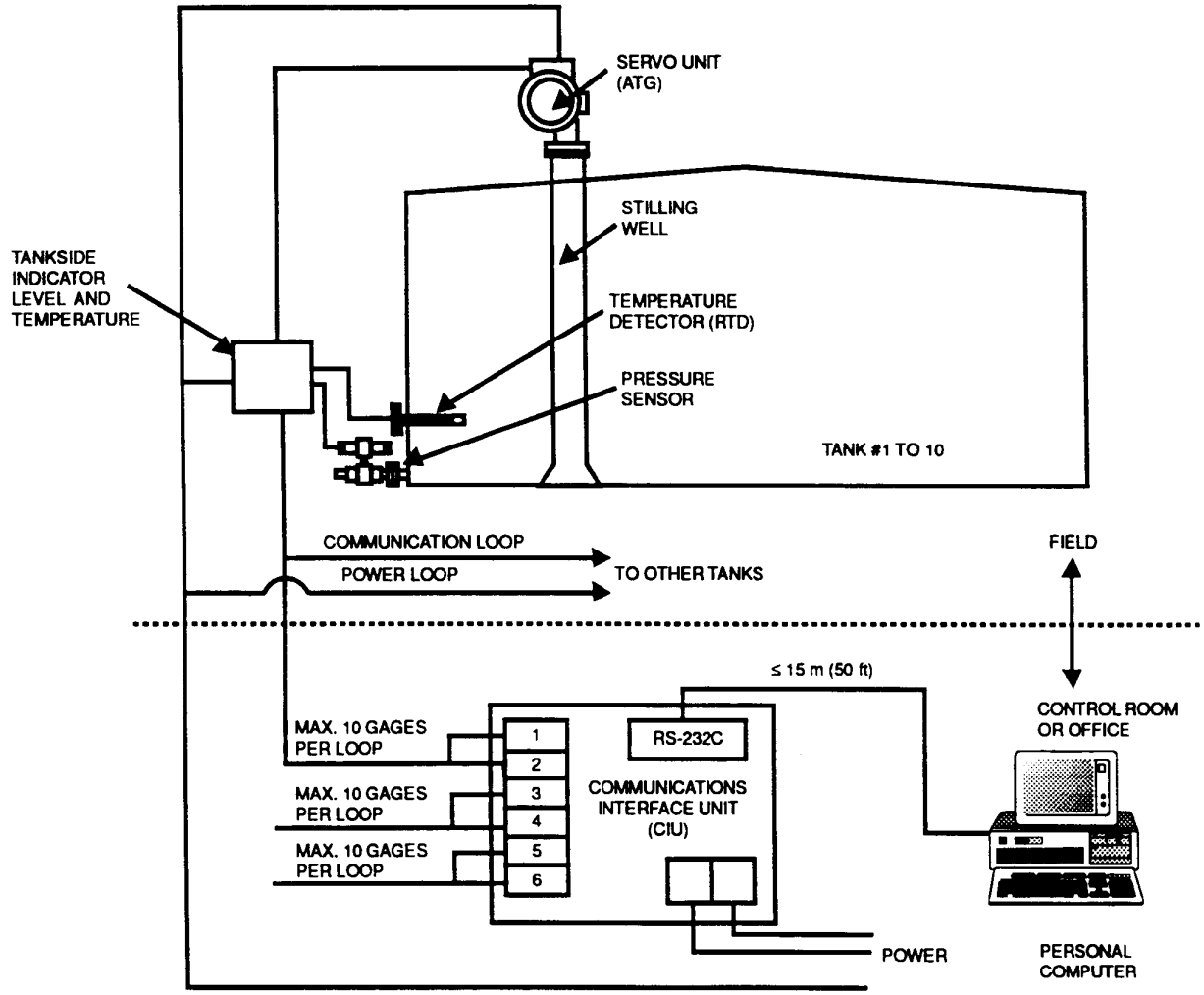

Figure 4: Hybrid System Schematic

NOTE TO FIGURE 4: Other level gauges could also be integrated with pressure transmitters to configure a hybrid system.

3.4. Radar Gauging System

- Radar gauging systems use microwaves to determine tank ullage. A radar level gauge applies a synthesized, frequency modulated pulse technique for accurate measurement of liquid levels in all types of bulk storage tanks. The frequency and phase shift difference between the transmitted and reflected microwave sweep is proportional to the ullage measurement (distance between the tank top radar transmitter and the liquid surface).

- The microwave signal sweeps between 9.5–10.5 GHz and is generated by a voltage control oscillator (VCO) on top of the antenna unit. The signal is fed via the reflectometer to both the antenna feeder and the reference line. The short horn

antenna emits the radar signal as an elliptical beam with angles of 8 and 12 degrees for the two axis of the ellipse. The reflected signal is received by the same antenna and the distance (ullage) is computed from the Fourier transformed frequency spectrum of the received signal.

- A radar gauging system has no moving parts and provides fair level accuracy at a higher cost. A system schematic is presented in Figure 5.

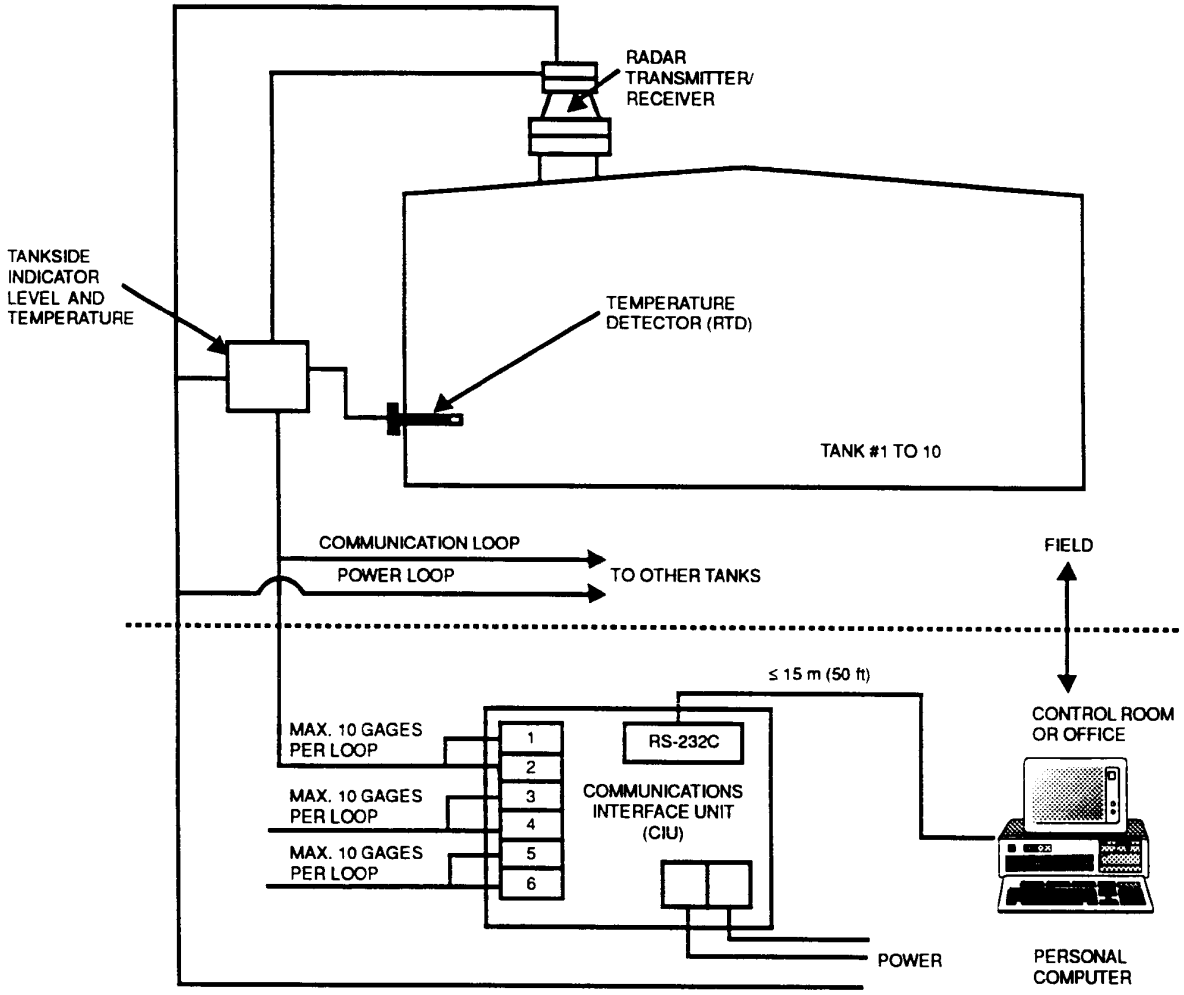

Figure 5: Radar Gauging System

3.4.1. Advantages

- Acceptable level accuracy when installed properly.
- Minimal maintenance, although the type of maintenance required is highly specialized.
- Level accuracy is not affected by product stratification.

- Can be used in automated process operations that depend on volume flow.
- Effective with extremely viscous products, such as asphalt, where gauges that contact the product may be unreliable.

3.4.2. Disadvantages

- Manual (operator) input of density to calculate mass limits the calculation accuracy.
- Because it is roof mounted and measures ullage, the system could give erroneous results if the reference point moves due to flexing of the tank bottom, shell or roof. The impact of shell deformation on movement of datum can be included in the software if the data is available.
- An averaging temperature probe is required on tanks greater than 30 m (100 ft) in diameter and tanks with temperature stratification to calculate volume at a temperature of 15°C (60°F).

3.4.3. Hybrid System

This system can be fitted with a hydrostatic transmitter in a configuration similar to that shown in Figure 4 and described in Section 3.3.3 of this Tutorial. It also becomes a "hybrid" system.

3.5. Magnetostrictive Gauging System

Magnetostrictive systems use the intersection of magnetic fields to determine the level in a storage tank. Magnetostrictive gauges operate in the following manner:

- The electronics assembly initiates a short, low current pulse onto a wire that runs through the center of the waveguide material. A timer is started simultaneously.
- The pulse, along with the magnetic field it generates, travels the length of the gauge.
- When the pulse reaches the float, the magnetic field from the pulse interacts with the magnetic field generated from the float (see Figure 6) and initiates a torsional "twist" in the waveguide material.
- This physical "twist" creates a sonic wave that travels along the waveguide in both directions and is detected by the strain gauge in the electronics assembly. The timer is stopped as soon as this return signal is detected. The distance from the float (magnet) can be determined accurately based on the time and on the signal transmission properties of the individual waveguide material.
- If a second float is present on the gauge, a second "twist" can be detected and recorded as the interface level.
- Up to six RTDs are spaced along the inside of the outer rod of the gauge to provide either an average product temperature or a temperature profile of the tank.

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- They provide accurate level measurement at a reasonable cost. Mobil has successfully used this system in underground tanks. However, Mobil has not had any experience on the use of this system on aboveground storage tanks. Use of this system for aboveground storage tanks is limited to tanks with a diameter of 12 m (40 ft) or less. A system schematic is presented in Figure 7.

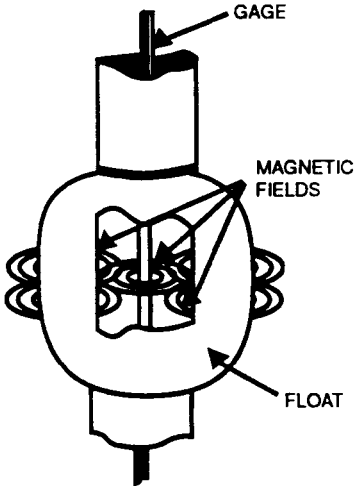

Figure 6: Magnetostrictive Gauging System

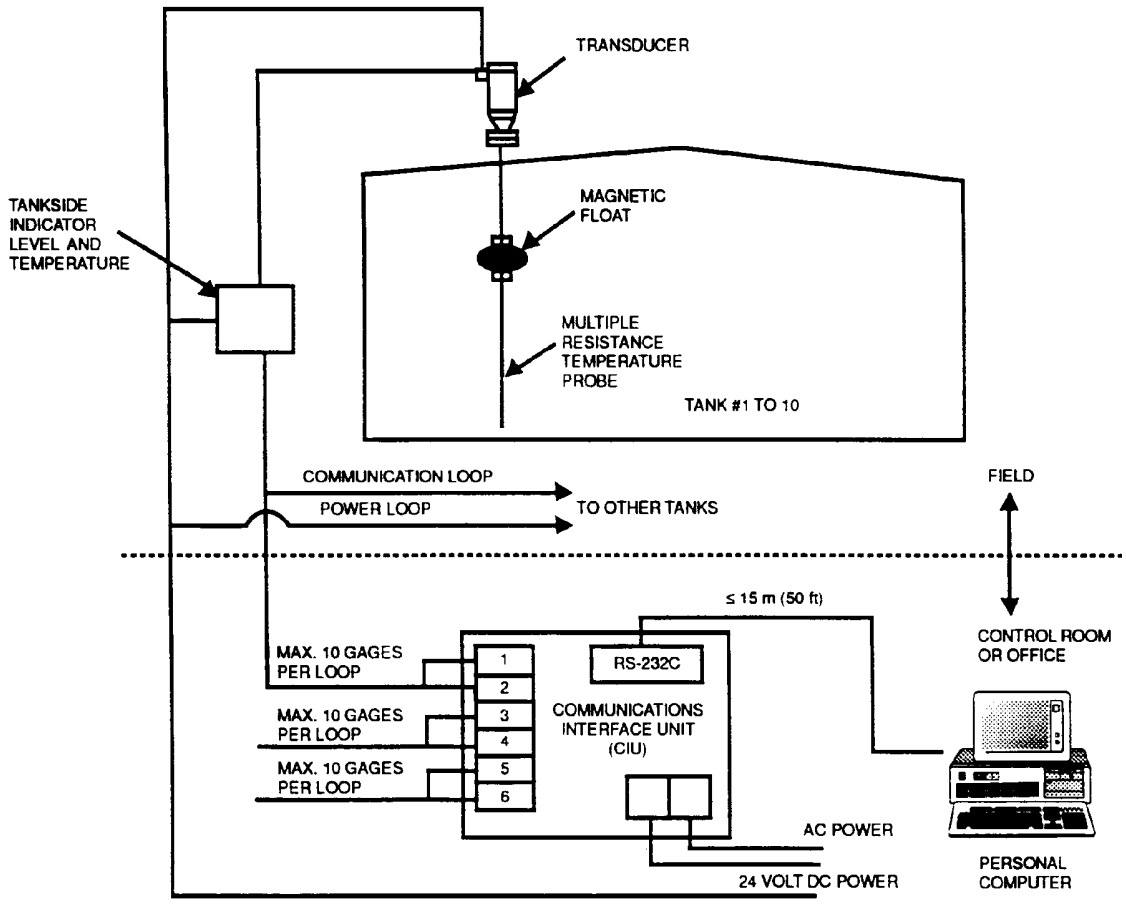

Figure 7: Magnetostrictive Gauging System Schematic

3.5.1. Advantages

- Good level accuracy at a moderate cost.
- Capable of detecting water interface when provided with an additional float.
- Level accuracy is not affected by product stratification in the tank.
- Can be used in automated process operations that depend on volume flow.
- The averaging temperature probe is mounted within the magnetostrictive tube; thus, only one roof nozzle is required to install the level and temperature probe.
- When provided with an averaging temperature probe, the magnetostrictive system has limited leak detection capability based on standard volume at 15°C (60°F).

3.5.2. Disadvantages

- The maintenance frequencies are unknown at this time. The possibility exists of the float binding against the magnetostrictive tube; therefore, this system is not recommended for viscous products.
- Manual (operator) input of density to calculate mass limits the calculation accuracy.
- Because it is roof mounted and measures ullage, the system could give erroneous results if the reference point moves due to flexing of the tank bottom, shell or roof. The impact of shell deformation on movement of datum can be included in the software if that data is available.
- Tanks greater than 30 m (100 ft) in diameter and tanks with temperature stratification require an averaging temperature probe to calculate volume at a temperature of 15°C (60°F). However, the averaging temperature probe can be mounted in the magnetostrictive tube, thereby eliminating the need for a second roof nozzle.

3.5.3. Hybrid

If this system is fitted with a hydrostatic gauge and transmitter, it can provide accurate real time mass, level and density measurements. This arrangement provides the combined advantages of both a level and HTG systems, similar to that shown in Figure 4.

3.6. Bubbler Gauging System

This system operates on hydrostatic pressure measurement by means of air bubbling through the product and provides average accuracy on mass basis at a reasonable cost. A system schematic is presented in Figure 8.

Because of its limited accuracy, requirement of dry compressed air (not available at most marketing terminals) and high maintenance requirements, this system is not recommended and, therefore, is not included in Appendix A, Table A–2 of this Tutorial.

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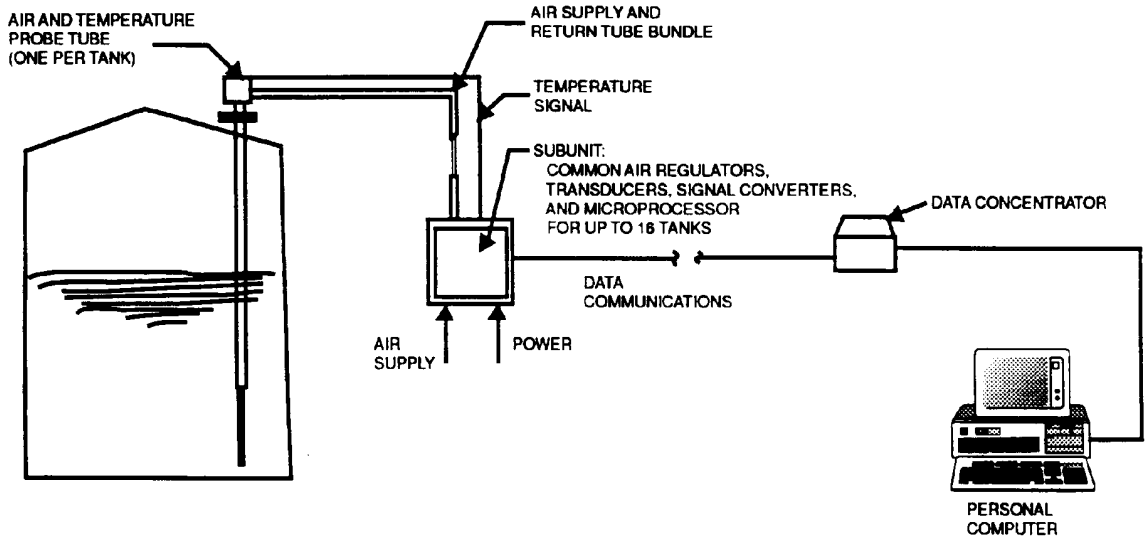

Figure 8: Bubbler Gauging System Schematic

3.6.1. Advantages

- Accuracy is not adversely affected by movement of the reference point.
- Simple, low-cost installation.
- Mass calculations are not affected by stratification and temperature effect; the mass is calculated on the basis of measurement of hydrostatic pressure and cross-sectional area of the tank at that point.
- Provides real time density when both bubbler outlets are submerged in product.

3.6.2. Disadvantages

- Lower accuracy.
- Higher maintenance requirement.
- Product stratification affects the accuracy of the measured density and, therefore, the volume and level accuracy. This is because the observed density is used in calculation of volume and level.
- When the upper probe (see Figure 8) is uncovered, the level is calculated on the last observed density. If product is received in the tank so that this probe remains uncovered, the calculated volume and level may not be accurate if the density of the product received is different from that of product in the tank. This problem can be minimized by the operator sampling the product and inputting the laboratory-observed density through the system software.
- Continuous consumption of dry compressed air.

- Tankside indicator not available.

3.7. Float and Tape Gauging System

- Float and tape gauging systems mechanically link a buoyant float, which rides the liquid surface, to a dial counter that indicates tank innage by means of a nongraduated perforated metal tape. A system schematic is presented in Figure 9.
- This system is generally provided with electronic transmitters for remote readout and a spot resistance temperature device (RTD) with transmitter to measure level and to calculate volume at a temperature of 15°C (60°F).
- This is a simple system that provides limited accuracy (±25 mm [1 in]) at a moderate cost. The accuracy limitation is due to considerable friction between moving parts, varying product density, limited minimum readout of 1.6 mm ($^{1}/_{16}$ in), possible play between the measuring drum and the tape and temperature effect on the length of the tape.

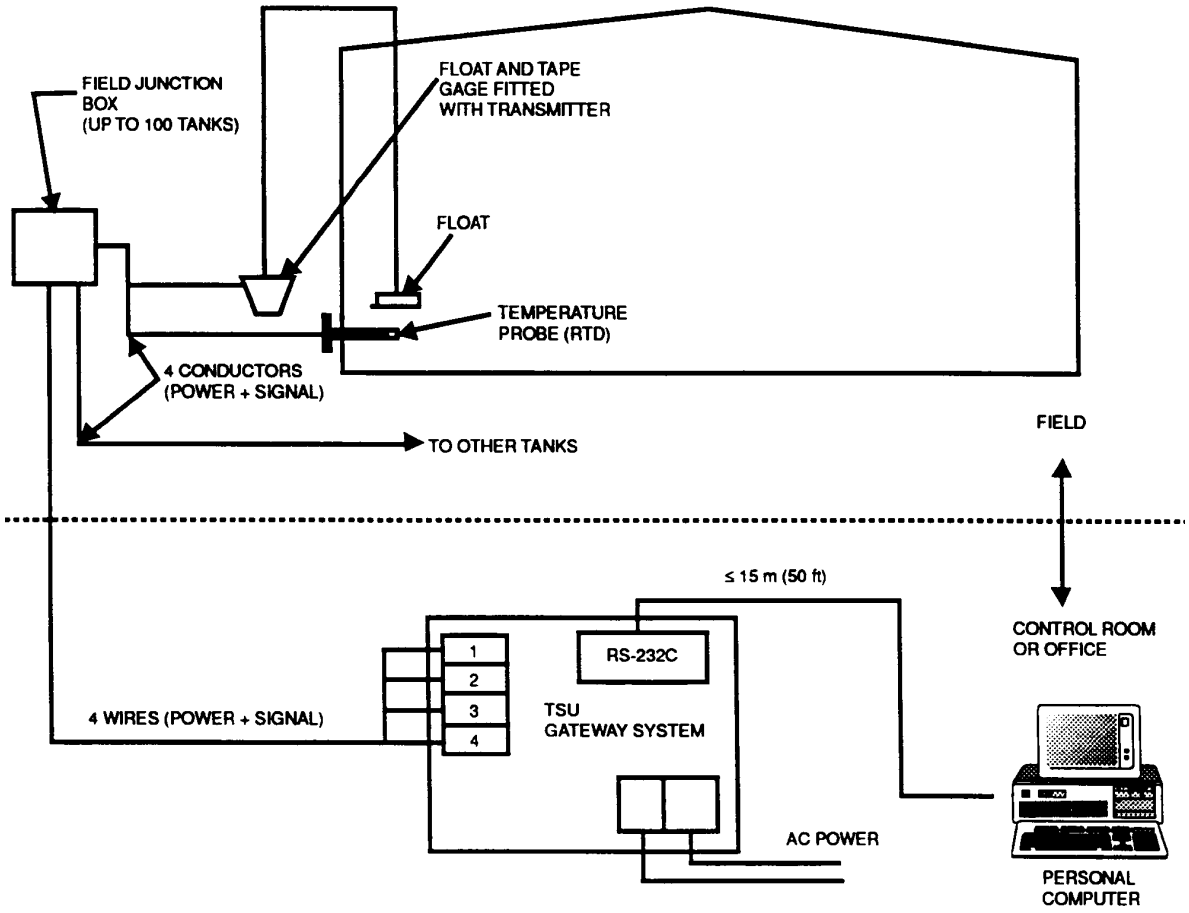

Figure 9: Float and Tape Gauging System Schematic

3.7.1. Advantages

- It is inexpensive if installed in a new tank as long as the level accuracy stated in Section 3.7 of this Tutorial is acceptable.
- A large number of existing tanks use this system and retrofitting may be expensive.

3.7.2. Disadvantages

- Accuracy is limited.
- The system requires a considerable maintenance effort. The possibility does exist that product may cling to the tape and eventually deposit in the tape-drum housing; this must be periodically drained. This is not only time consuming but also results in environmental problems and a possible fire hazard.
- Manual (operator) input of density to calculate mass limits the calculation accuracy.

- Because it is roof mounted and measures outage, it could give erroneous results if the reference point moves due to flexing of the tank bottom, shell or roof.
- Tanks greater than 30 m (100 ft) in diameter and tanks with temperature stratification require an averaging temperature probe to calculate volume at a temperature of 15°C (60°F).
- Does not provide leak detection capability.
- Unsuitable for automated process operations.

4. Considerations and Criteria

4.1. Objectives of Automatic Tank Gauging

The primary objectives are:

- To gauge the tank contents without human involvement on a continuous basis
- To display level, mass (or both) and temperature at tankside and in the control room
- To provide necessary alarms in a timely manner to the operator or any integrated automated system

Other objectives may include:

- Remotely monitor (such as in a central office located outside the plant) and display product levels in tank(s)
- Remotely monitor and display water level in tank(s), in addition to the product level
- Use software/hardware to provide volume at a temperature of 15°C (60°F)
- Use the system to provide leak detection capability during nonoperating periods
- Transmit information on available ullage to the central inventory control system
- Integrate the volume/mass information in the automatic process control and/or terminal systems
- Use the system in custody transfer of products
- Indication of an operating tank
- Provide tankside alarm contacts
- Use the system to monitor tank filling operations and provide for software advisory before alarm points are reached (see Appendix D of this Tutorial)

- Furnish information on a daily reconciliation of product by grade

4.2. ATG System Selection

- Future plant requirements shall be considered when selecting an ATG system.
- The system selection process shall include evaluation of each of the ATG methods described in Section 3 of this Tutorial with respect to any of the applicable criteria from the following:
  - Accuracy
  - Repeatability/reliability
  - Self-checking capability
  - Ease of maintenance
  - Sensor and system response time
  - Emergency operation
  - Integration with other systems
  - Cost
  - Remote user interface capability
  - Custody transfer requirements

  NOTE: Before selecting a system, the custody transfer approval status shall be checked with local authorities.
- Appendix A, Table A–2 of this Tutorial, shows a comparison of various systems.

4.3. Site Survey

The site survey shall include the following:

- Site plan showing all tanks with sizes and product service.
- Identification of aboveground and belowground tanks.
- Identification of probable location of control processing unit (CPU) and display monitor (CRT) in the central control room. Also, identification of any other required tie-ins.
- Availability of system power.
- Requirements for uninterruptible power supply (UPS).
- Copies of calibration charts and reference points for all tanks.

- Identification of existing automatic tank gauges that are likely to be reused and integrated into the new system (not recommended).

4.4. Operating Practices

The operating practices shall be identified so that the software design can address any specific requirements.

The following are some examples of operating practices that need to be determined:

- Stock reconciliation at the end of the day (2400 hours) or at the end of each shift
- Reconciliation of the physical inventory with the automatic tank gauging inventory
- Any other specific operating practice unique to a particular location, such as local authority requirements

4.5. Related Facilities

- Some of the related facilities that may be integrated with the ATG are as follows:
  - Lube batch blending and fuels blending
  - Inventory control (integration with automated terminal systems)
  - Automatic low level shutdown of product pumps and/or tank mixers
  - Automated receipt of product from pipeline supply company
  - Automated receipt of product from refinery tanks to day tanks
  - Intertank transfer within facility
- The related facilities shall be thoroughly investigated and integration planned at an early date to avoid costly system modification.
- If the location already has a distributed control system (DCS), the ATG shall be integrated into the existing system. In this case, the impact of this integration on the process response time shall be evaluated and steps taken so that there are no adverse effects on the overall system and any associated automated processes.

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5. System Design–Aboveground Tanks

5.1. General

The equipment shall be approved for its intended use by Underwriters Laboratories Inc. (UL), Factory Mutual Engineering & Research Corporation (FM) or other recognized approving authority with jurisdiction in the area where the system is to be installed.

The mechanical installation details for the various ATG systems described in Section 3 of this Tutorial are shown in MP 32-P-22. When ATG systems are to be used for custody transfer, the local authority requirements shall be incorporated as well.

5.2. System Layout

5.2.1. General

A plot plan showing all tanks included in the project shall be prepared. It shall clearly show the following:

- Tank location, size, type, diameter and height
- Tank dikes with elevations of toe and top
- Location of office or control room
- Topographic survey showing 1 ft contours and types of pavement
- Location of power supply source
- Area classification

The above information, along with system requirements (see Appendix B of this Tutorial), shall be used to prepare detailed mechanical and electrical layouts.

5.2.2. Mechanical

The mechanical layout and details shall include, but not be limited to, the following:

- Method of installation of sensors.
- Any modifications to tank (i.e., installation of shell and/or roof nozzles).
- Provision of access to the sensors.

- Method of installation of local readout devices (e.g., spot temperature, tankside indicator).
- Stipulation of requirements for tank cleaning, as necessary.
- Orientation of sensor location so that sensor accuracy is not affected due to either receipt or withdrawal of the product.
- When using HTG pressure transmitters on tanks containing heated viscous products (lube oils), it is necessary to heat trace and insulate the tank nozzle in accordance with MP 00-P-04 and MP 34-P-10, respectively, to improve response time of the pressure transmitter.
- Location of sensors/electrical conduits so that the arrangement avoids interference with the existing tank appurtenances and fire protection equipment.
- The preferred location of datum plate, spot RTD, averaging temperature probe, safety railing, hand gauging/antirotation pipe, automatic gauging sensor and averaging thermometer as detailed in Figures 10–14 and MP 32-P-22.

When equipment has to be installed on tanks and pressure vessels in service, the nozzles on the shell and roof shall be installed and tested in accordance with applicable MEPS and local regulations, codes and practices.

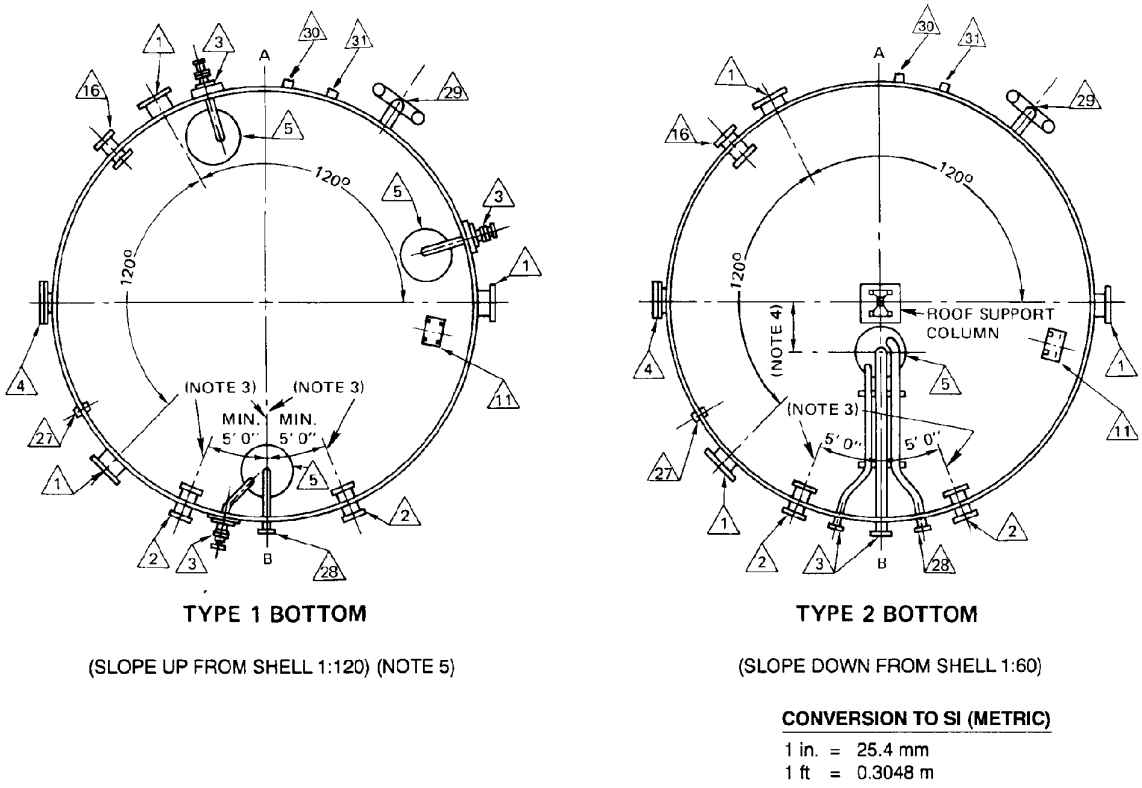

Figure 10: Typical Layout and Dimensions

Legend for Types 1 and 2 Bottoms:

1	Shell manholes, tank diameters (Note 1):	11	Datum plate (Note 6)
	Up to 25 ft: one NPS 24	16	Roff drain nozzle (for open-top floating roof tanks only)
	>25 to 100 ft: Two NPS 24 (180 degrees apart)	27	Thermowell connection NPS 1/CL 3000 coupling with round head plug 2 ft above tank bottom
	>100 ft: Three NPS 24 (120 degrees apart)	28	Stripping nozzle (Note 6)
2	Inlet and suction nozzles (Note 2)	29	H-level and HH-level alarms (Located near dike entrance or main path through tank farm.)
3	Water drawoff	30	Automatic gauging connections on shell (Note 6)

4	Foam chambers (Note 6)	31	Mobil hydrostatic tank leak test connections
5	Sump (for Type 1 bottoms, number required is the same as number of shell manholes)		

NOTES TO FIGURE 10:

1. A flush-type cleanout shall be substituted for one of the manways where sludge is expected (e.g., crude oil).
2. Two suction nozzles are required where hydrocarbon is skimmed from water.
3. Connections may be parallel. Recommended for large-diameter piping.
4. 3 ft 6 in from centerline of support column for cone roof tank. Sumps may be located eccentrically in large-diameter tanks.
5. Slope shall be increased to compensate for predicted center-to-edge settlement, so that the slope up from the shell after predicted settlement is 1:120.
6. Provide only when shown on T1401C01 (see the Mobil Data Sheets) or in project specifications.

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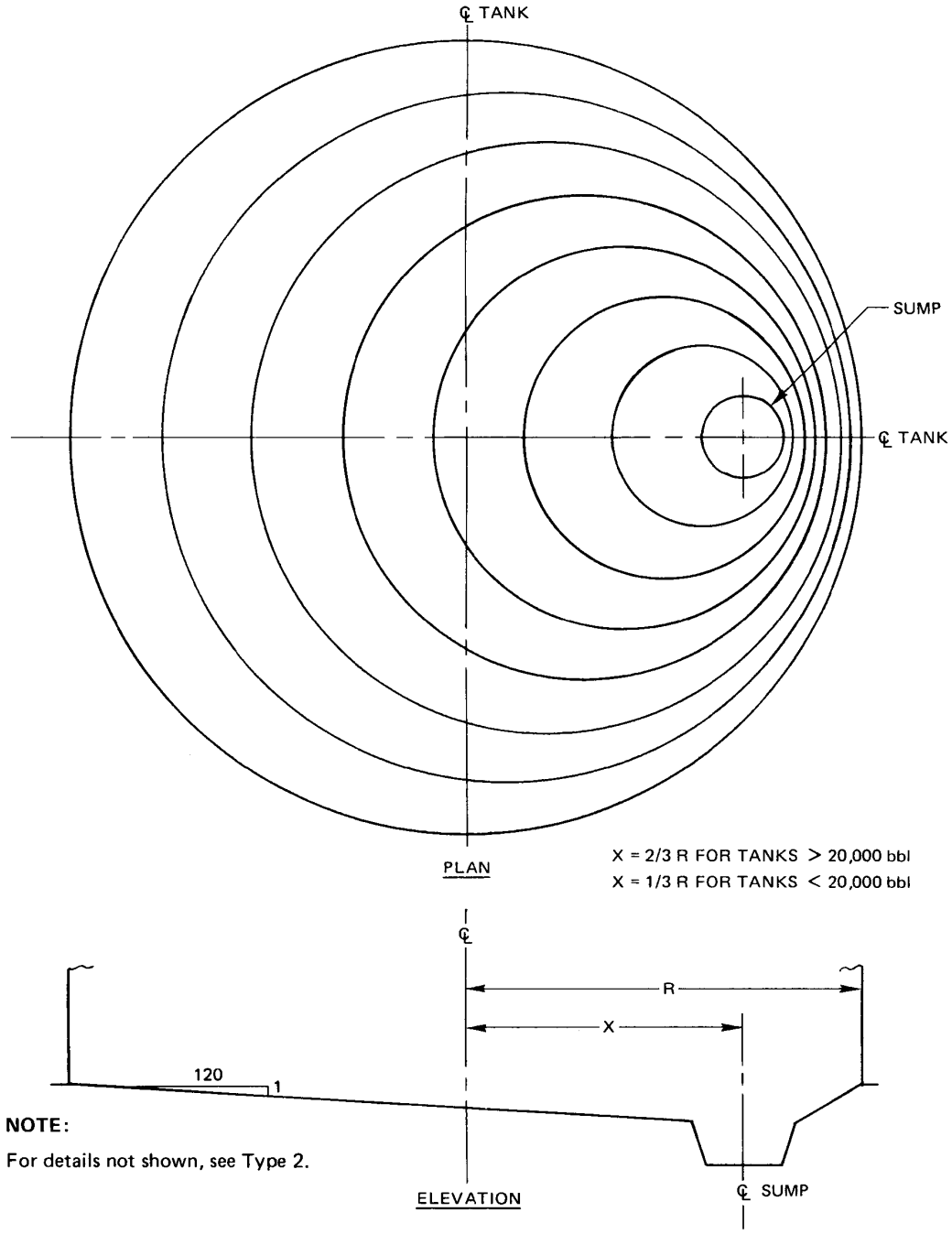

TYPE 3 BOTTOM

(MOBIL PIPE LINE COMPANY)

Figure 11: Storage Tanks–Location of Shell and Bottom Connections and Appurtenances

TYPICAL LAYOUT AND DIMENSIONS

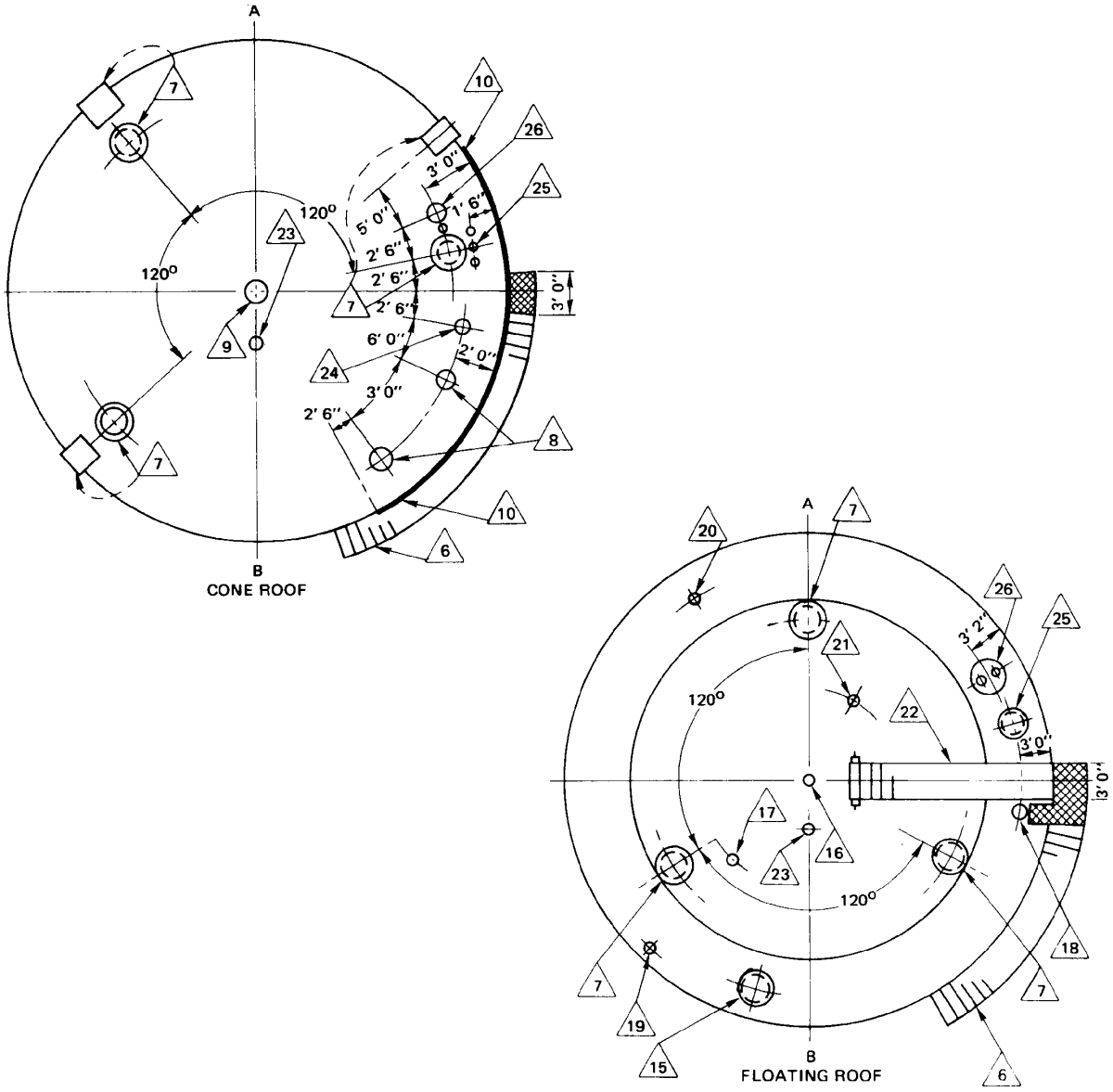

Figure 12: Storage Tanks–Location of Roof Connections and Appurtenances

Legend for Cone Roof and Floating Roof Tanks:

6	Circular stairway unless otherwise specified	17	Emergency drain for double deck roofs (Note 2)
7	Roof manholes, tank diameters:	18	Gauging/antirotation pipe (Notes 3 and 4)

	Up to 50 ft: One NPS 24	19	Rimvent for shoe seals (Note 2)
	>50 to 100 ft: Two NPS 24 (180 degrees apart)	20	Roof supports (number as required)
	>100 ft: Three NPS 24 (120 degrees apart)	21	Automatic bleeder vent, leg operated
	Hatch-type combination manways/vents (shown by dashed line) located on the roof perimeter shall be used for freely vented cone roof tanks with internal floating roofs.	22	Rolling ladder with articulated steps
8	Vent connections	23	Water gauging connection over sump (Note 3 and 5)
9	Scaffold cable support	24	Temperature, gauging and sampling hatch (Notes 3 and 4)
10	Railing	25	Automatic gauge, ground or remote reading (Note 1)
15	Pontoon manholes, NPS 20 minimum, one per compartment	26	Averaging thermometer (Note 1)
16	Roof drain		

NOTES TO FIGURE 12:

1. Provide only when shown on T1401C01 (see the Mobil Data Sheets) or in project specifications.
2. Manufacture's design.
3. Shand & Jurs or Oceco gauge hatch.
4. Location to be accessible from platform.
5. For floating roof, provide extension to avoid product flowing onto roof.

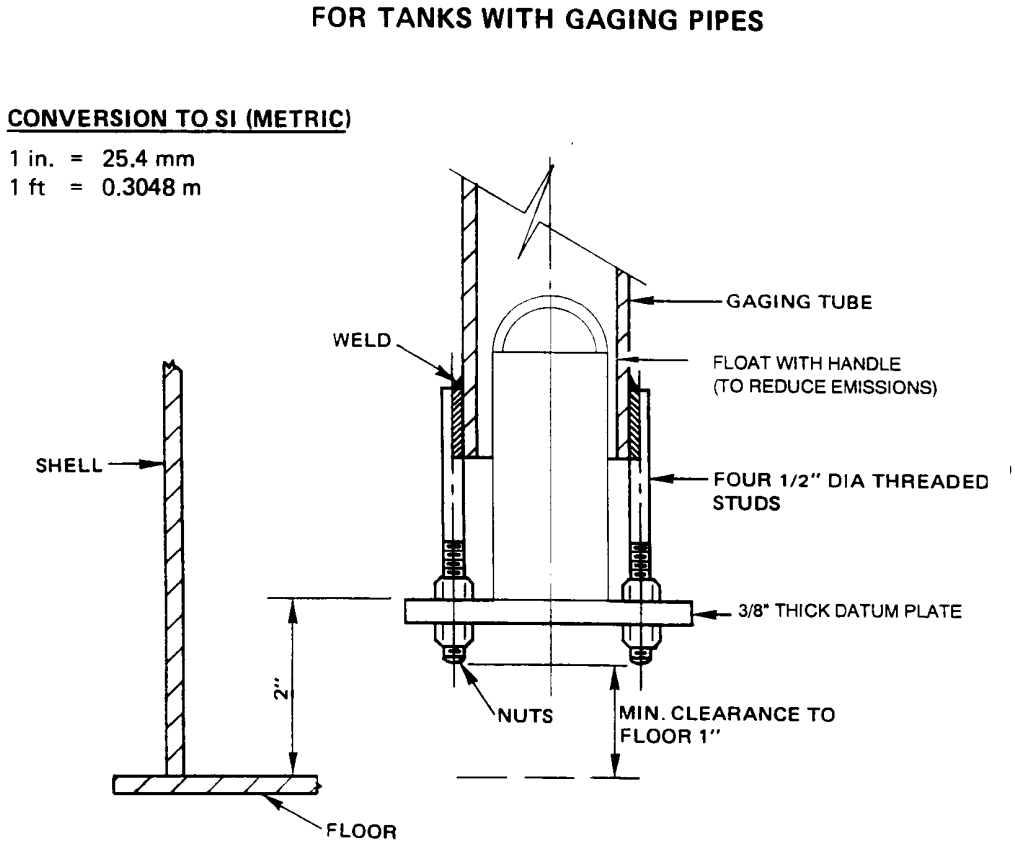

Figure 13: Storage Tanks–Gauging Datum Plate

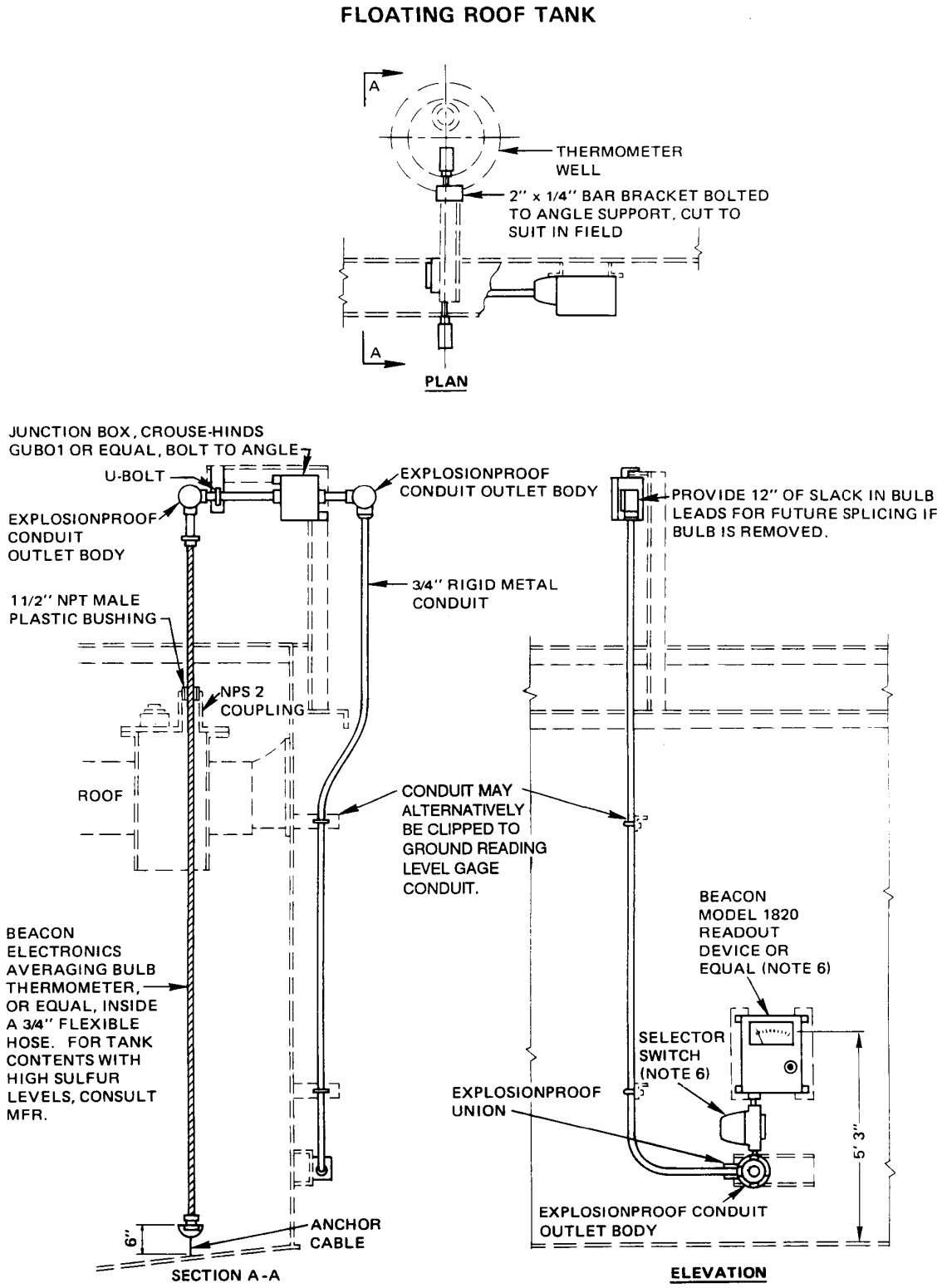
FLOATING ROOF TANK
A
THERMOMETER WELL
2" x 1/4" BAR BRACKET BOLTED TO ANGLE SUPPORT, CUT TO SUIT IN FIELD
A
PLAN
JUNCTION BOX, CROUSE-HINDS GUB01 OR EQUAL, BOLT TO ANGLE
U-BOLT
EXPLOSIONPROOF CONDUIT OUTLET BODY
EXPLOSIONPROOF CONDUIT OUTLET BODY
PROVIDE 12" OF SLACK IN BULB LEADS FOR FUTURE SPLICING IF BULB IS REMOVED.
3/4" RIGID METAL CONDUIT
1 1/2" NPT MALE PLASTIC BUSHING
NPS 2 COUPLING
ROOF
CONDUIT MAY ALTERNATIVELY BE CLIPPED TO GROUND READING LEVEL GAGE CONDUIT.
BEACON MODEL 1820 READOUT DEVICE OR EQUAL (NOTE 6)
BEACON ELECTRONICS AVERAGING BULB THERMOMETER, OR EQUAL, INSIDE A 3/4" FLEXIBLE HOSE. FOR TANK CONTENTS WITH HIGH SULFUR LEVELS, CONSULT MFR.
SELECTOR SWITCH (NOTE 6)
EXPLOSIONPROOF UNION
5' 3"
6"
ANCHOR CABLE
EXPLOSIONPROOF CONDUIT OUTLET BODY
SECTION A-A
ELEVATION

Figure 14: Storage Tanks: Ground Reading Averaging Thermometer

NOTES TO FIGURE 14:

1. All equipment, appurtenances and fittings shown by dashed lines shall be furnished and installed by the tank fabricator.
2. Averaging thermometer bulb assembly, selector switch, readout device and all materials shown by solid lines shall be furnished and installed by the electrical contractor.
3. Electrical contractor to check insulation resistance of thermometer bulb before and after installation with proper meter.
4. Fittings equivalent to those specified may be substituted when approved by Mobil.
5. When averaging thermometer is to be a future installation, the tank fabricator shall furnish and install complete wire assembly, brackets and blanked-off nozzle, as shown.
6. An alternative to the fixed temperature readout device and selector switch is Beacon Electronics jackbox 1640 JB mounted on the tank and Model 1640 portable temperature indicator.

5.2.3. Electrical

Electrical layout and design shall be as detailed in EPT 15-T-18A and EPT 15-T-18B.

- Shielded cables shall be adequately grounded.
- The system architecture shall be selected so that the sensors and transmitters can be changed at a later date without affecting the system wiring. The system shall support various types of sensors so that a common local area network (LAN) or local control network (LCN) loop can be used. Consequently, necessary software changes can be made while avoiding major rewiring expense. A typical system architecture is shown in Figure 15.
- Where the automatic tank gauging system is interlocked with automatic process work or to automatic pipeline receipt system, a UPS system is recommended as a source of power.
- If the system is not provided with UPS, surge voltage protection is recommended for installation on both the microprocessor and the printer.
- Conduit sizing shall include required spare capacity.
- Underground conduit installation is recommended to limit mutual inductance (noise) and damage due to lightning.
- Installation of 50 percent spare conductors is recommended in the system, so that any wiring failures can be easily handled by using available spares.
- Lightning protection is essential in the system circuit design.
- When the system is required to transmit information over telephone lines, lightning protection shall be considered in the system design.

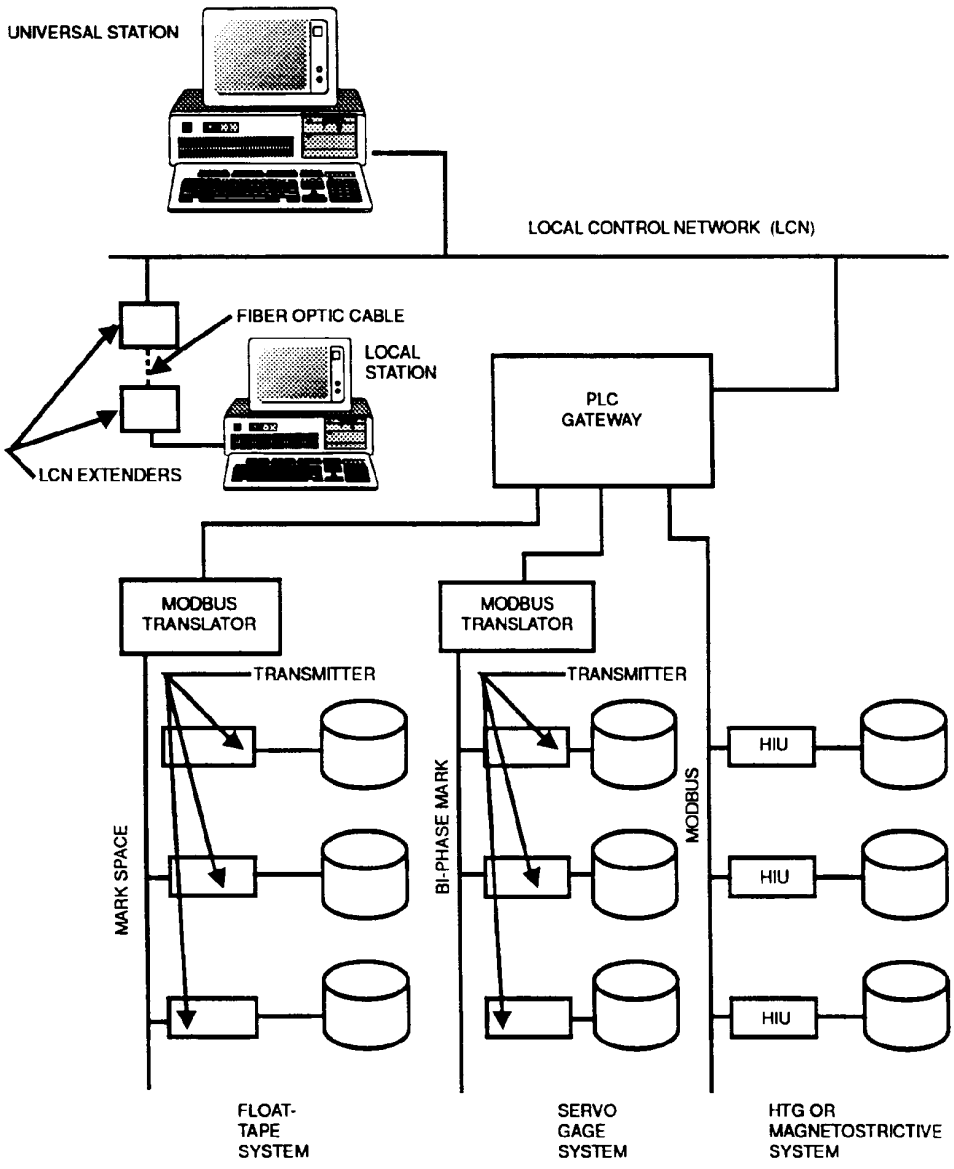

Figure 15: Aboveground Tank System

5.3. System Software and Communication Protocol

The system software shall be designed to meet the objectives listed in Section 4.1 of this Tutorial. Appendix B of this Tutorial shows a typical checklist that shall be completed for each tank.

The software shall:

- Be compatible with other control systems included in integration.

- Be interactive, easy to use, with easily changed parameters.
- Have a graphics package that displays the information shown in Table 1 either in tabular or graphic format.

The system shall accept manual (operator) inputs of:

- Density
- Temperature
- Adjustable interlocks and alarms (levels, volume and mass)
- Leak detection setup
- Password-protected capability to change database

Complete documentation for the software shall be obtained from the vendor and made available at the operating location.

5.3.1. Signal Transmission

The recommended method of signal transmission is to digitize the signal at the sensor and then transmit it through an RS-485 (twisted pair) protocol. Implementation of the RS-485 protocol makes the system almost universal and the transmitters can communicate raw data directly to a DCS or automated terminal system. RS-232C protocol requires data to be processed by the tank gauging CPU before going to a DCS or automated terminal system.

5.3.2. Typical Display Requirement

Typical display requirements are summarized in Table 1.

Table 1: Typical Display Requirement

1. Tank ID and service		
2. Tank dimensions	Diameter and height or diameter and length	
3. Tank capacity	Maximum gross volume Safe fill gross volume Observed gross volume Observed net volume* Observed net volume at 15°C (60°F) Available gross ullage by volume	
4. Tank mass	Maximum gross mass Safe fill gross mass Observed gross mass Observed net mass Observed net mass at 15°C (60°F)	

	Available gross ullage by mass	
5. Level	Maximum level, m (ft) Safe fill level Hi-Hi level alarm set point Hi level alarm set point Low level alarm set point Observed level Observed level at 15°C (60°F) Available ullage level	
6. Density	Reference density range Observed density, kg/m^3 (lb/ft^3) Observed density at 15°C (60°F) Operator inputted density at 15°C (60°F)	
7. Temperature	Reference temperature range Observed temperature, °C (°F)	
8. Rates	Emptying rate (outloading) Filling rate (product receipt)	
9. Interlocks	Level Mass Volume	
10. Alarms	Level, mass and volume	Hi-Hi Hi Low Floating
	Density	High Low
	Temperature	High Low
	System malfunction	
11. Leak detection setup		

* Calculated by subtracting volume of water present from the total measured/calculated volume.

5.4. Integration with Other Systems

The system design shall include "sequence of operation" of each process if the automatic tank gauging system is to be integrated with process work or other information systems.

When the system is integrated with other process operations or interlocks, it is essential to run a failure analysis to avoid any catastrophic results or to build in safeguards against them. Appendix D of this Tutorial describes integration of ATGs with high level alarm systems.

6. System Description–Underground Tanks

6.1. General

6.1.1. Components

Automatic tank gauging (ATG) system components consist of the following:

- Level sensor (which could be a float or an ultrasonic transducer)
- Electronic transmitter
- Receiver-decoder
- Printer

A tankside (local) indicator is not considered necessary.

6.1.2. Leak Detection Capability

Leak detection capability shall be incorporated into the system, since most local jurisdictions require (or in the future may require) such a provision. This necessitates installation of an averaging temperature probe or multiple probes.

In addition, it is desirable to incorporate capability to detect leaks in:

1. The annular space of a double wall tank
2. Manways, reservoirs and the annular space of the double wall piping
3. Discharge piping from submersible pump to the product dispensers
4. Observation wells

6.2. Two ATG Systems

Two ATG systems used by Mobil are described as follows.

6.2.1. Magnetostrictive Tank Gauging System

This system operates on measurement of the interlinking magnetic field from a fixed reference point. For a detailed description of operation, see Section 3.5 of this Tutorial. The system schematic configuration is shown in Figure 16.

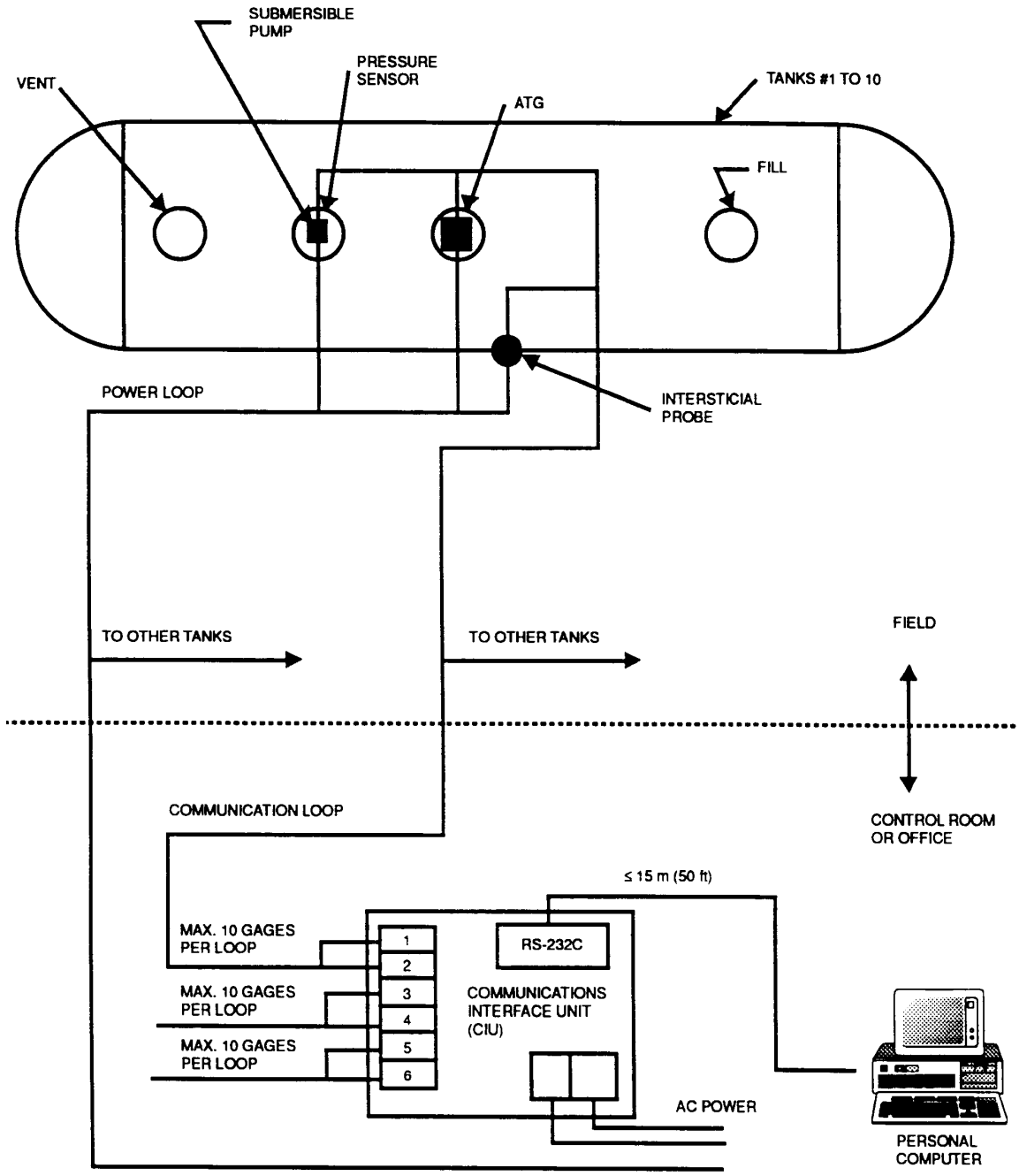

Figure 16: Magnetostrictive Gauging System Schematic

6.2.1.1. Advantages

- Good level accuracy at a moderate cost.
- Excellent repeatability.

- The averaging temperature probe is mounted within the magnetostrictive tube and requires only one nozzle to install the level and the temperature probe.
- Capability of detecting water interface when provided with an additional float.
- Capability to meet Environmental Protection Agency (EPA) requirements for leak detection when provided with a printer and necessary programming.

6.2.1.2. Disadvantages

- The possibility exists of the float binding against the magnetostrictive tube and, therefore, the system is not recommended for viscous products.
- The system requires integration with other devices for detecting leaks in the annular space of double wall tanks and piping, manways, reservoirs and discharge piping. When planning to purchase this system, the client is advised to ensure that this integration is available.

6.2.2. Ultrasonic Tank Gauging System

This system operates on ultrasonic sound waves and measures the time taken by the sound pulse and its reflected echo to travel between the ultrasonic transducer and the surface of the liquid being monitored. The system schematic is shown in Figure 17.

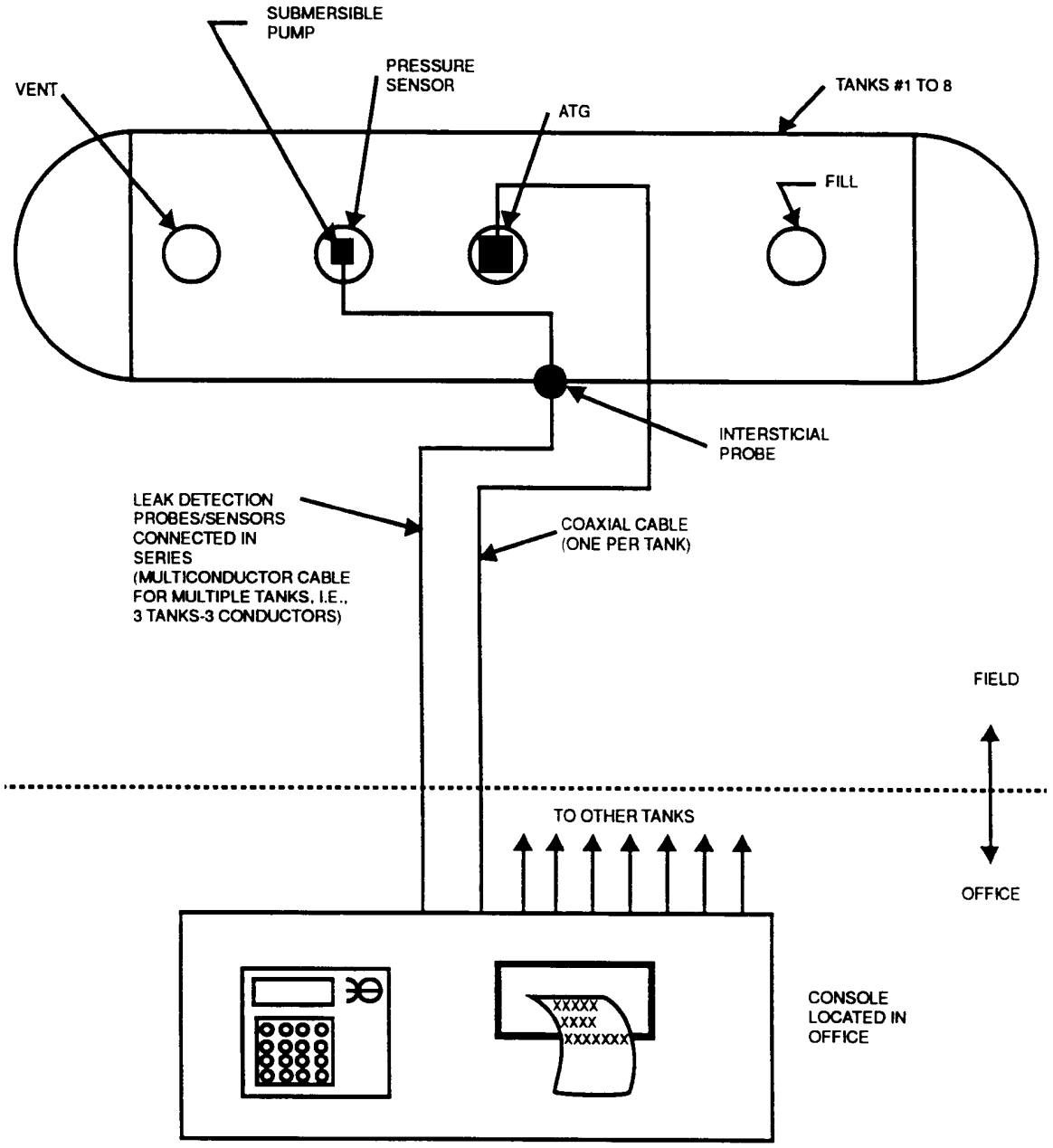

Figure 17: Ultrasonic Tank Gauging System Schematic

6.2.2.1. Advantages

- Approved for use in underground tanks by the EPA. Meets U.S. federal performance standards established by the U.S. Environmental Protection Agency for leak detection rate of 0.2 gallon per hour at 95 percent probability of detection. (Note: This tests the "wetted perimeter" of the tank only. It is not a "system" test.)

- Meets U.S. federal performance standards for measuring water bottoms with an accuracy of 3 mm ($^1/_8$ in).
- Because there are no moving parts, the maintenance requirement is minimal.
- The manufacturers furnish a fully integrated system including ATG and leak detection devices.
- Average temperature calculation includes the largest percentage of the liquid as compared with other methods available.

6.2.2.2. Disadvantages

- Possibility of false alarms.
- Accuracy is adversely affected by any interference in the path of sound waves.

7. Considerations, Criteria and System Design– Underground Tanks

7.1. Objectives of Automatic Tank Gauging

The primary objectives are:

- To gauge the tank automatically without human involvement on a continuous basis
- To provide leak detection and record-keeping capabilities acceptable to EPA or local authorities

Other objectives are:

- Remotely monitor and display level, temperature, volume, standard volume and ullage space in each tank on the system
- Transmit data on available ullage by product grade to central inventory control system
- Provide software alarms for the following:
  - Ordering point
  - Low level
  - High level
  - High water level
- Automatically generate product replenishment orders

- Monitor tank filling operation with software advisory before alarm points are reached
- Provide daily reconciliation for each shift by each product grade
- Interface with dispenser control system in order to reconcile meter reading tank inventory

7.2. System Selection

Future requirements shall be considered when selecting an ATG system.

System selection process shall include evaluation of the systems presented in Section 6 of this Tutorial with respect to any of the applicable criteria from the following:

- EPA or local authority approval
- Local electrical and/or safety authority approval
- Accuracy
- Repeatability/reliability
- Self-checking capability
- Ease of maintenance
- Emergency operation
- Integration with other systems
- Cost
- Remote user interface capability

7.3. System Design

7.3.1. Site Survey

The site survey shall include the following:

- Site plan showing all tanks with tank sizes and product service
- Location of dispensers
- Location of salesroom or kiosk
- Identify source of power and requirement of UPS
- Copies of calibration charts for tanks
- Identify whether any existing automatic tank gauges are likely to be reused and integrated into the new system

- Identify any other systems to be integrated with the ATG
- Identify conduit requirements

7.3.2. Operating Practices

The following are some examples of operating practices that need to be considered:

- Is stock reconciliation required at the end of each shift?
- Is physical inventory conducted on the last day of the month? Is it necessary to reconcile the physical inventory with ATG?
- Determine the requirements of the graphics package.

7.3.3. Design Criteria

- The system layout shall include a plot plan showing types of pavements, all tanks, dispensing systems, salesrooms, ingresses, egresses, manholes/reservoirs/trenches requiring leak detection and source of power.
- Prepare Appendix B of this Tutorial clearly showing required information.
- Prepare mechanical layout that shall include, but not be limited to, the following:
  - Method of installation of sensors
  - Any tank modifications
  - Provision of adequate access to sensors and electronics
  - Provide means to remove any sensor easily for repairs/replacement
- Prepare an electrical layout that shall include, but not be limited to, the following:
  - Detailed wiring diagram showing all terminations
  - A complete plan showing routing of power and signal wiring
  - Conduit sizes and details
  - Area classification drawing in line with National Electrical Code (NEC) or in accordance with local requirements
  - Details of UPS system
  - Details of system integration
- Prepare sequence of operation.

- Prepare failure analysis and provide safeguards against catastrophic failure.

8. System Testing, Calibration, Startup and Training– Aboveground and Underground Tanks

- Testing shall be an integral part of the system design and shall include, but not be limited to, the following:
  - Loop checks for continuity.
  - Test insulation resistance in accordance with MP 33-P-11 and cable/wire manufacturer's specifications.
- Before any attempt is made to calibrate the instruments and start the system, a point-to-point connection check shall be performed and any problems resolved.

NOTE: In order to maintain accuracy and reliability, regular calibration and testing is required.

8.1. Accuracy Verification

- After calibration is completed, system accuracy versus manual gauging shall be verified.
- Accuracy verification shall include at least three different readings:
  - One at the top
  - One near the middle
  - One about 3 m (10 ft) above the bottom of the tank

  When this is not possible at startup, at least one reading (preferably at middle) shall be verified by manual gauging and the other two readings recorded during normal operations.
- Any excessive differences (greater than vendor-guaranteed accuracy) between manual and ATG shall be brought to the attention of the system vendor so that the necessary offsets can be programmed into the system software.
- The accuracy of the remote temperature readout shall also be verified with the local temperature readout.

8.2. Training

Before the vendor turns over the system, the purchaser's operators shall be given adequate training in operation and maintenance of the system. The manufacturer's representative

shall provide the training. During this training, two copies of the O&M (Operation and Maintenance) manuals shall be provided.

Appendix A: Systems Comparison–Aboveground Tanks

Table A–1: Systems Comparison–Advantages and Disadvantages

Advantages / Disadvantages*	ATG Systems**					
	HTG	**Servo**	**Radar**	**Magneto-strictive**	**Bubbler**	**Float & Tape**
Advantages						
1. Superior mass accuracy	X					
2. Low installation cost	X			X	X	X
3. Low maintenance cost	X	X	X	X (Note 1)	X	
4. Leak detection capability	X	X		X (Note 2)		
5. Water detection capability	X (Note 4)	X	X (Note 4)	X (Note 4)		
6. Recommended for automatic process	X	X		X		
7. Real time density measurement	X				X	
8. Superior level accuracy		X (Note 5)				
9. Good level accuracy			X (Note 5)	X		
10. Mass calculations unaffected by temperature effects/stratification	X					X
Disadvantages						
1. Lower mass accuracy		X			X	
2. Lower level accuracy	X				X	
3. Lowest level accuracy						X
4. High installation cost		X	X		X	
5. Accuracy affected by product stratification	X				X	

Advantages / Disadvantages*	ATG Systems**					
	HTG	**Servo**	**Radar**	**Magneto-strictive**	**Bubbler**	**Float & Tape**
6. Accuracy affected by movement of reference point		X (Note 7)	X (Note 7)	X (Note 7)		
7. Higher maintenance cost					X	
8. Higher operating cost					X	
9. Tankside indicator not available					X	

* For details on advantages and disadvantages, see Section 5 of this Tutorial.

** For systems comparison involving accuracy, repeatability, response time and relative mechanical cost, see Table A-2.

NOTES TO TABLE A–1:

1. Maintenance frequency not known at this time.
2. Limited capability if provided with averaging temperature probe.
3. Limited capability due to lower mass accuracy.
4. Supplemental water level detector required.
5. If installed on stilling well.
6. For installation on existing tanks, see Section 5 of this Tutorial.
7. Can be improved if installed properly (see Section 5 of this Tutorial).

Table A–2: Systems Comparison–30 x 12 m (100 x 40 ft) Cone Roof Aboveground Storage Tank

	Type of System					
	Mech. Float and Tape	**Servo Gauge (Note 2)**	**Hydrostatic (Note 10)**	**Magneto-strictive (Note 11)**	**Radar**	**Hybrid (Note 7)**
Accuracy						
Level	±25 mm (1 in)	±1 mm (0.04 in)	±25 mm (1 in)	±1.6 mm (0.063 in) (Note 6)	±2 mm (0.06 in)	±1 mm (0.04 in) (Note 2)

	Type of System					
	Mech. Float and Tape	**Servo Gauge (Note 2)**	**Hydrostatic (Note 10)**	**Magneto-strictive (Note 11)**	**Radar**	**Hybrid (Note 7)**
Spot	±0.4°C (0.7°F)	±0.4°C (0.7°F)	±0.4°C (0.7°F)	NA	±0.4°C (0.7°F)	±0.4°C (0.7°F)
MRT	NA	±0.4°C (0.7°F)	NA	±0.4°C (0.7°F)	±0.4°C (0.7°F)	±0.4°C (0.7°F)
Standard Density	±0.01% (Note 1)	±0.01% (Note 1)	±0.10 to 0.25%	±0.01% (Note 1)	±0.10 to 0.25%	±0.10 to 0.25%
Mass	±0.30% (Note 1)	±0.12% (Note 1)	±0.02%	±0.15% (Note 1)	±0.13%	±0.02%
Standard Volume	±0.35%	±0.07%	±0.12 to 0.3%	±0.11%	±0.08%	±0.07%
Repeatability	±3 mm (±0.12 in)	±0.5 mm (0.02 in)	±0.2%	±.15 mm (0.005 in)	±1 mm (±0.04 in)	±0.5 mm (0.02 in)
Sensor Response Time	NA	$^{1}/_{30}$ second	$^{1}/_{20}$ second	$^{1}/_{100}$ second	$^{1}/_{30}$ second	$^{1}/_{30}$ second
Self Checking	NA	yes	yes	yes	yes	yes
System Response Time	NA	14 tanks /second	(Note 9)	17.5 sec for 80 tanks	14 tanks /second	14 tanks /second
Maximum Tanks Per Loop	10	10 (Note 3)	31 (Note 8)	10 (Note 3)	10 (Note 3)	10 (Note 3)
(Note 12) Mech. Cost/ Tank New	$8,000	$15,000 (Note 5)	$10,000	$8,000	$19,000	$19,000 (Note 5)
(Note 12) Mech. Cost/ Tank Existing	$17,000	$26,000 (Note 4)	$13,000	$10,000	$24,000	$30,000 (Note 4)
Components Included	Float and tape, tankside indicator, spot RTD and transmitter	Servo gauge, tankside indicator, spot RTD and stilling well	Two HTGs, tankside indicator and spot RTD	Magnetostrictive gauge, tankside indicator and MRT	Radar gauge, tankside indicator and spot RTD	Servo gauge, tankside indicator, MRT and stilling well

NOTES TO TABLE A–2:

1. Dependent on "manual" density input. In above tabulation, its accuracy is assumed to be ±0.01 percent.
2. Advanced technology servo gauge.
3. 30 tanks per CIU.
4. Coat includes tank cleaning with minimal sludge removal and stilling well. If level accuracy of ±2 mm is acceptable, stilling well may not be required. If existing nozzle can be used, the cost would be reduced.
5. If stilling well is not required, the cost could be reduced.
6. Accuracy is based on direct digital access (DDA) gauge.
7. Hybrid consisting of servo gauge and HTG combination.
8. 24 tanks/loop on DCS, 31 tanks/loop and 93 tanks per CIU on DOS system.
9. 1–2 seconds for 24 tanks on DCS; on DOS system, 93 tanks in 10 seconds.
10. HTG system is more accurate on short time period transfer versus inventory accuracy over a longer period (greater than 24 hours).
11. Magnetostrictive systems are not recommended on large aboveground tanks since Mobil does not (in 1992) have enough experience with the use of this system on such tanks.
12. Typical costs (1992) for total (material and labor) mechanical installation. Actual costs will have to be developed for each application.
13. The system supports a total of eight loops in eight tanks.

LEGEND:

NA = Not applicable

Sec. = Second

Sys. = System

Resp. = Response

MRT = Multiple resistance temperature

Appendix B: System Requirements Tank Data– Aboveground and Underground Storage Tanks

Tank # _____ (Circle applicable type and installation–see Legend.)			
Type: CR, FROT, FRGD, CRIFR, SPH, SPHD, PV, HD			
Product Stored:			
Installation: AG, UG		Material: CS/AS/FG	
Diameter:	m (ft)	Height:	m (ft)
Length:	m (ft)	Max. fill:	m (ft)
		Safe fill	m (ft)
Available (Unused) Appurtenances			
Strapping Data			
Calibration Charts			
Instruments Installed			
Required Interlocks:	Low Level Cut Off		
	High Level Cut Off		
	High-High Level Cut Off		
	Pipeline Supply Interlocks		
Method of Receipt:	Pipeline/Tanker/Barge/Refinery		
	Transfer/Tank Truck/Tank Car/Other		

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Other Requirements:	Accuracy	
	Repeatability	
	Response Time	
	Local Level Readout	
	Local Temperature Readout	
	Remote Level Readout	
	Remote Temperature Readout	
	Remote Water Level Readout	
	Remote Volume (at Natural Temperature) Readout	
	Remote Volume at 15°C (60°F) Readout	
	Remote Mass Readout	
	Remote Rate of Product Transfer	
	Leak Detection Required:	Yes/No
Custody Transfer Required:		Yes/No
Other System Integration:	Batch Blending:	Yes/No
	ATS:	Yes/No
	Oil Movement Control:	Yes/No
Sequence of Operation:		

LEGEND:

AG	Aboveground
AS	Alloy Steel
CR	Cone Roof
CRIFR	Cone Roof with Internal Floating Roof
CS	Carbon Steel
FRGD	Floating Roof with Geodesic Dome
FROT	Floating Roof Open Top
HD	Horizontal–Dome Ends
ATS	Automated Terminal System
MAX	Maximum
PV	Pressure Vessel (horizontal or vertical)
SPH	Spherical
SPHD	Spheroid
UG	Underground

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Appendix C: Leak Detection Procedure with HTG System

1. General

HTG systems can be used for on-line leak detection and monitoring of idle storage tanks. The leak detection is based on the mass deviation input to the software that activates the associated alarm.

The mass deviation alarm (MDA) is activated during the period when the tank is not scheduled to be operated for either receipt or withdrawal of the product. Therefore, this alarm shall be deactivated when the above tank is put into an operating mode.

2. Mass Deviation Set Point

The equipment manufacturers normally provide a default value of 454 kg (1000 lb) mass deviation alarm in the software supplied with the system. However, it is preferable to input a more sensitive value for this set point based on the following calculation:

- Assumptions:
  - Upper range value of the pressure sensor is 207 kPa (30 psi).
  - Overall pressure sensor accuracy of ±0.03 percent of 207 kPa (30 psi) = 0.062 kPa (0.009 psi).
- Set Point Calculation:
  - The objective is to calculate mass change based on a change in pressure of 0.062 kPa (0.009 psi).
  - The applicable formula is:

SI (Metric) Units

$$M = \frac{0.102 \_ P \_ G}{H}$$

Customary Units

$$M = \frac{19.25 \_ P \_ G}{H}$$

- Where:

  M = mass in kg (lb)

  P = pressure change in kPa (psi)

  G = maximum tank capacity in L (US gal)

  H = product in m (ft)

- Example:

  For a 10 ft diameter tank with a capacity of 11,750 gallons at 20 ft level:

$$M = \frac{19.25 \_ 0.009 \_ 11{,}750}{20}$$

$$M = 101.78\,\text{lb}\ (\text{round to}\ 102\,\text{lb})$$

NOTE: Use of the above value is 10 times more sensitive than the default value of 1000 lb.

3. Inputting Mass Deviation Alarm Set Point

Follow manufacturer's instructions for accessing data base.

Input MDA for each tank.

4. Performing On-line Leak Detection

On-line leak detection can be performed when required as follows:

- Identify the tank to be tested.
- Close receipt and discharge valves.
- Close thermal relief system valves at the tank.

NOTE: Thermal relief system gate valves shall be closed only if this test is to be performed during a period when ambient temperature is likely to fall (for example, at night). Immediately after the test, the thermal relief system valves shall be opened and locked in open position so that the thermal relief system is operational.

- Enable MDA.
- Initiate trend log for MDA for the duration of the test (a minimum of eight hours is recommended). The longer the duration, the more accurate the test is likely to be.

CAUTION: Although the on-line test is very accurate, it shall only be used as an indication of a possible leak. If leak probability is indicated, a certified tank test shall be initiated immediately to confirm the results of the on-line test.

Appendix D: Integration with High Level Alarm Systems

1. General

Automatic tank gauging systems can be used for high level alarms in the following cases (see MP 32-P-22 for definitions, equipment and other requirements):

- Tanks containing Class I flammable liquids that have a separate, independent, high/high level alarm system.
- Tanks where the alarm does not perform a safety interlock or shutdown function.
- Tanks containing other than Class I liquids where the alarm system provides interlock or shutdown functions.

However, local operating division practices and/or codes may exclude other classes of products.

When high/high level alarms cannot be included in an ATG system per the above requirements, they shall be totally separate and independent. This includes the actual field detecting devices as well as the annunciator and audible alarm device.

2. System Integration

An example of integrating the two systems is as follows.

2.1. High Level Condition or High-High (Noninterlocking Function)

In this condition, either the independent high level sensor or ATG "contact" can initiate an alarm. The independent high level alarm signal can be "validated" by the ATG system by interconnecting (integrating) the two systems in parallel. The output can then be connected to an alarm and annunciator panel and, if appropriate, the pipeline company's control room to advise of a possible overfill condition. The signal can be further validated by being connected through a limit switch on the receipt manifold inlet valve, verifying that an actual receipt is taking place.

2.2. High/High Level Condition (Interlocking Function)

When a tank reaches this condition, the independent contact or ATG system initiates the alarm signal and an audible and visual alarm is annunciated locally. No verification is made through the ATG system (see MP 32-P-22). The alarm signal can then either shut down the pipeline company's pump or, alternatively, close a motor-operated valve in the terminal at the pipeline receipt manifold or both. It shall be noted that, if the signal is used to shut down the pipeline pump, an agreement with the pipeline company serving the terminal is required. Also, the pipeline company may require, before the pump shutdown signal is transmitted, that a verification be made that the receiving valve to the terminal is, in fact, open. This can be accomplished by including a limit switch on the main receipt valve to indicate that it is in the open position. However, in no case shall the annunciation of the alarm signal be delayed.

If a valve is installed, its closing speed shall be carefully chosen to prevent hydraulic shock from damaging the terminal or the pipeline company's equipment.

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Lease Automatic Custody Transfer Unit

MP 32-P-20

July 1998 Draft

Scope

This Mobil Engineering Practice (MEP) defines the minimum requirements for the design, materials, fabrication, inspection and documentation of Lease Automatic Custody Transfer units (LACT). When included, a meter prover becomes an integral part of the LACT system.

Version 0

Table of Contents

Scope **1**

1. References **3**

1.1. MEPS–Mobil Engineering Practices 3

1.2. Mobil Data Sheets 3

1.3. Mobil Tutorials 3

1.4. API–American Petroleum Institute 3

1.5. MMS–Minerals Management Service, U.S. Department of the Interior 4

1.6. NEMA–National Electrical Manufacturers Association 4

2. General **4**

3. Modifications to API SPEC 11N **5**

Modifications to Section 1: Scope **5**

Modifications to Section 3: Shop Assembly Testing Warranty **5**

Modifications to Section 4: Mechanical and Hydraulic Specifications **5**

Modifications to Section 5: Charging Pump and Motor **6**

Modifications to Section 6: Strainer and/or (Optional) Air/Gas Eliminator **7**

Modifications to Section 7: Sediment and Water Probe, Monitor and Diverter Valve **7**

Modifications to Section 9: Thermowell and Three-Way Prover Loop **7**

Modifications to Section 10: Back-Pressure Valve **7**

Modifications to Section 11: Sampling **8**

Modifications to Section 12: Electrical **8**

4. Meter Provers: Modifications to API MPMS 4.2 ..... **10**

Modifications to Section 2: Conventional Pipe Provers **10**

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1. References

The following publications form a part of this Practice. Unless otherwise specified herein, use the latest edition.

1.1. MEPS–Mobil Engineering Practices

MP 00-P-82	Packaged Units-General Requirements
MP 01-P-12	Miscellaneous Buildings
MP 15-P-01	Centrifugal Pumps (API 610)
MP 15-P-02	Positive Displacement Pumps-Rotary
MP 32-P-07	Safety Interlock Systems and Alarms
MP 33-P-17	Electrical - LV Induction Motors
MP 33-P-30	Electrical - Small Packaged Equipment

1.2. Mobil Data Sheets

Mobil Data Sheets	Mobil Data Sheet Home Page
T3220C01	Instrumentation - Lease Automatic Custody Transfer Unit - Customary Units
T3220M01	Instrumentation - Lease Automatic Custody Transfer Unit - Metric Units
D3220C01	Instrumentation - Lease Automatic Custody Transfer Unit - Documentation Requirements Sheet
I3220C01	Instrumentation - Lease Automatic Custody Transfer Unit - Inspection & Testing Requirements Sheet

1.3. Mobil Tutorials

EPT 05-T-03	Flow Measurement and Control

1.4. API–American Petroleum Institute

API MPMS 4.2	Manual of Petroleum Measurement Standards Chapter 4 - Proving Systems

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	Section 2 - Conventional Pipe Provers (API STD 1101, 2531, 2533, 2534) (R 1993) First Edition
API MPMS 6.1	Manual of Petroleum Measurement Standards Chapter 6 - Metering Assemblies Section 1 - Lease Automatic Custody Transfer (LACT) Systems Second Edition (R 1996)
API SPEC 11N	Specification for Lease Automatic Custody Transfer (LACT) Equipment Fourth Edition

1.5. MMS–Minerals Management Service, U.S. Department of the Interior

MMS OCS	Outer Continental Shelf Orders

1.6. NEMA–National Electrical Manufacturers Association

NEMA 250	Enclosures for Electrical Equipment (1000 Volts Maximum)

2. General

The design, materials, fabrication, inspection and documentation of Lease Automatic Custody Transfer units shall be in accordance with requirements of this MEP, unless superceded by more stringent local regulations.

The technical requirements for LACT units are based on API SPEC 11N complemented by API MPMS 6.1. The technical requirements for meter provers are based on API MPMS 4.2.

Subparts H and L of MMS OCS apply only to offshore LACT units.

Materials of construction shall be suitable for the process fluids. A minimum corrosion allowance of 1.27 mm (0.05 in) shall be used unless otherwise specified.

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3. Modifications to API SPEC 11N

The following items correspond to the paragraph numbering within API SPEC 11N and reflect additions, substitutions, modifications and deletions. All provisions of API SPEC 11N that are not revised or deleted remain in force.

Modifications to Section 1: Scope

1.1. Modification: Coverage

This Practice imposes no restrictions on rates of flow or operating pressures.

Modifications to Section 3: Shop Assembly Testing Warranty

3.1. Addition

Shop assembly and testing requirements shall be called out in the particular job specifications.

Modifications to Section 4: Mechanical and Hydraulic Specifications

4.1. Addition: Skid Mounting

Drip pans shall be installed in all skids unless otherwise specified. Pans shall be sloped to permit complete drainage, with a minimum 100 mm (4 in) couplings located in the bottom or ends of the pan. Each drain opening shall be provided with a removable stainless steel screen to prevent entry of trash. Pan installations shall not create blind or inaccessible spots that cannot be sandblasted and painted. Such areas shall be sealed off with strap or plate.

Lifting pad eyes with machined holes shall be provided on each skid for field installation. The pad eyes shall be located in positions to balance the load and attain a "level" lift. The contractor shall notify Mobil if a spreader bar is required in order to prevent damage to equipment during lifts. When completed, each skid-mounted component shall be test-lifted to check the correctness of the pad eye location. Pad eye attachment welds shall be 100 percent ultrasonically inspected.

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4.6.1. New Title: Weatherproof Housings

4.6.1. New Paragraph: General

Whenever permanent housings are used, they shall completely cover the meter, BS&W monitor, sampler, sample container and sample probe. Whenever removable housings are used, they shall completely cover the meter and sampler; however, the charging pump and motor shall be external to the house.

All hydrocarbon vent ports shall be piped to a safe location outside of the housings.

All housings shall meet the requirements of NEMA 250 for a Type 4X enclosure.

4.6.2. New Title: Permanent Housings

4.6.2. New Paragraph

Permanent housing shall be free-standing, walk-in enclosures built as an integral part of the LACT unit skid. A hasp sized to accept only one padlock shall be provided for each entry door. Each door shall have mechanical provisions to hold the door fully open.

In addition to entry doors, housings shall be equipped with screened and shrouded openings that provide ventilation while keeping out blowing rain.

When required, thermostatically controlled electric space heaters shall be sized to maintain the housing internal temperature at a minimum of 4°C (40°F) during minimum ambient conditions.

The walls and roofs of houses provided with heaters shall be insulated. Roof and floor insulation shall have at least an R19 rating, and wall insulation shall have at least an R11 rating.

4.7. New Paragraph

For mechanical and hydraulic specifications, refer to MP 00-P-82 and the Mobil Data Sheets for this MEP.

Modifications to Section 5: Charging Pump and Motor

5.2. Modification

Centrifugal pumps shall be used and shall be in accordance with MP 15-P-01.

5.8. Modification

Materials of construction shall be in accordance with MP 15-P-01.

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5.9. Modification

Refer to MP 15-P-02.

5.11. Addition

Selection and application of motors shall be in accordance with MP 33-P-17. Each charge pump motor shall be provided with a control start/stop push button switch located at the LACT unit skid.

Modifications to Section 6: Strainer and/or (Optional) Air/Gas Eliminator

6.2. Modification

The strainer basket shall be 316 stainless steel as a minimum.

6.4. Modification

A differential pressure gauge shall be used for measuring pressure drop across the strainer.

Modifications to Section 7: Sediment and Water Probe, Monitor and Diverter Valve

Modifications to Section 9: Thermowell and Three-Way Prover Loop

9.5. Modification

Drain valves shall be included for the piping between the stub valves and the end connectors.

Modifications to Section 10: Back-Pressure Valve

10.1. Modification

A self-actuated type back-pressure control valve may be used.

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Modifications to Section 11: Sampling

11.2. Addition

When an inline static mixer is specified in the main oil line, it shall be flanged on each end and located no more than four pipe diameters upstream of the sampler probe (refer to Figure 3 of this MEP).

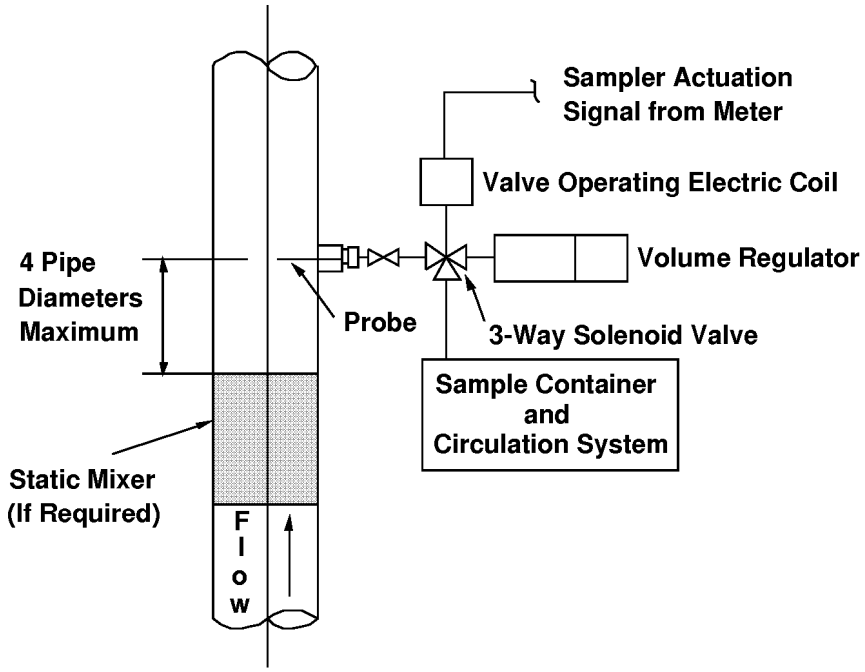

Figure 3: Typical Sample System

11.6. Modification

The circulating pump electric motor shall be explosion-proof. Each circulating pump motor shall be provided with a local control start/stop push button switch.

The inside walls of the sample container and associated piping shall be internally coated with an epoxy base paint. If stainless steel is used, the coating is not required.

The static mixer is optional and sized in accordance with the manufacturer's recommendations.

Modifications to Section 12: Electrical

MP 33-P-30 shall apply to this Section.

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12.1. Deletion

Refer to MP 33-P-30.

12.2. Deletion

Refer to MP 33-P-30.

12.3. Deletion

Refer to MP 33-P-30.

12.4.1. New Paragraph

A programmable logic controller (PLC) shall be used in place of a relay control panel.

12.6. Modification

Separate enclosures shall be provided for power and operation controls.

12.7. Addition

Transient and surge protection shall be added for all control instrumentation. Lightning arresters shall be provided for transformers supplying power to the unit.

12.8. Deletion

Refer to MP 33-P-30.

12.9. Deletion

Refer to MP 33-P-30.

12.10. Addition

... unless the control signal has sufficient capacity to operate the device.

12.11. Deletion

Refer to MP 33-P-30.

12.12. Deletion

Refer to MP 33-P-30.

12.14. Addition

Refer to MP 15-P-01 and/or MP 32-P-07.

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12.16. Addition

A grounding connection shall be provided between the ground system and the product receiver (for example, truck, barge, etc.).

4. Meter Provers: Modifications to API MPMS 4.2

The following items correspond to the paragraph numbering within API MPMS 4.2, and reflect additions, substitutions, modifications and deletions. All provisions of API MPMS 4.2 that are not revised or deleted remain in force. This MEP deals only with bidirectional provers.

Modifications to Section 2: Conventional Pipe Provers

4.2.2.2. Selection: Bidirectional Provers

Mobil prefers the bidirectional prover shown in Figure 2 of API MPMS 4.2 (see Figure 4 of this MEP below).

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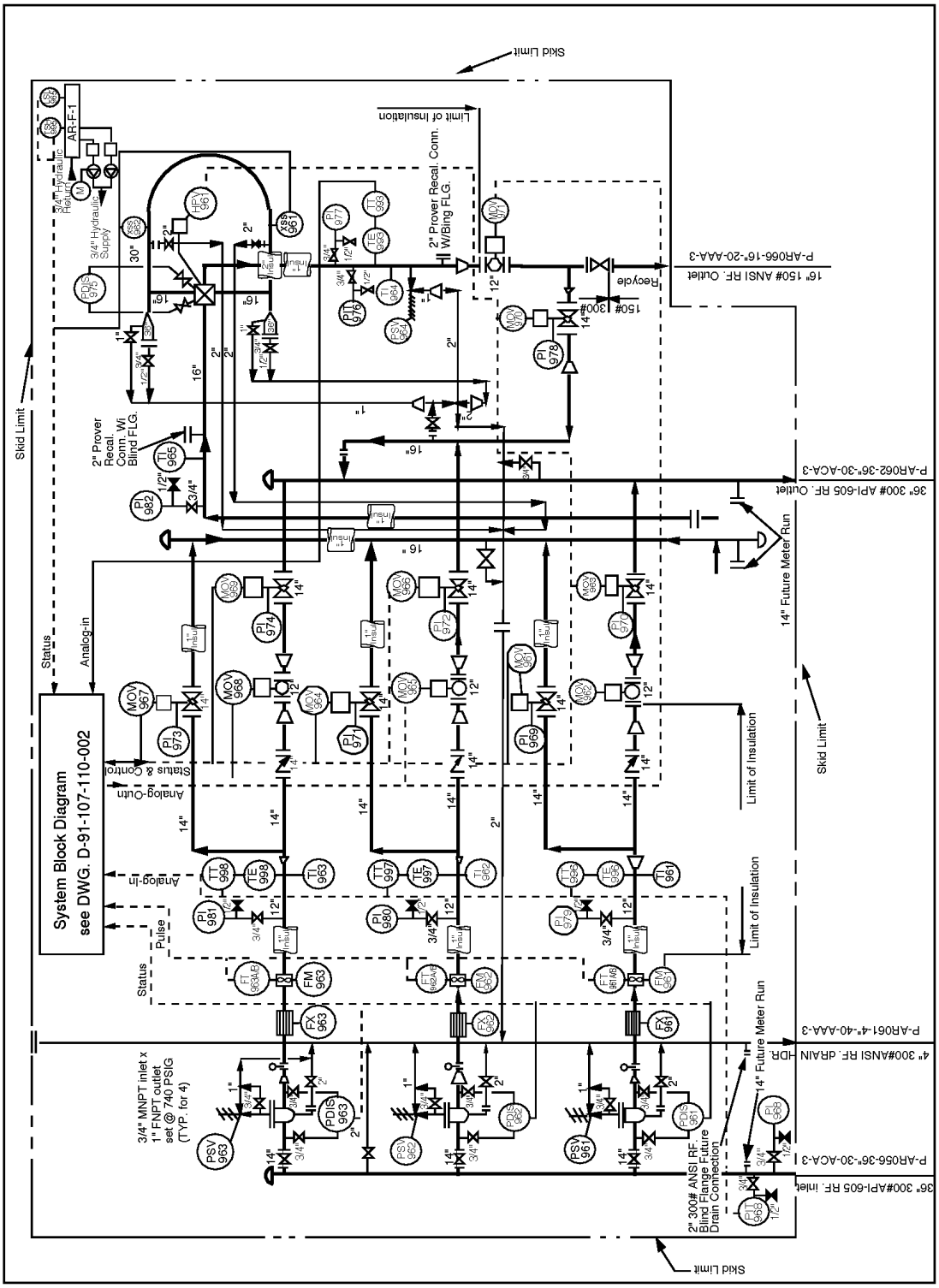

Figure 4: Typical Bidirectional U-type Sphere Prover–Customary Units 4.2.4 Equipment

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4.2.4.1. Addition: Materials and Fabrication

When a meter prover is required in a LACT system (refer to Figure 2), this system shall be fabricated as an operating unit by a recognized system vendor who is experienced in this field. This vendor shall be capable of providing all necessary certification; i.e., by National Bureau of Standards.

Whenever required, the meter prover shall be mounted on the LACT unit skid.

Provers shall be internally coated.

The out-of-roundness of the calibrated section shall not exceed the following:

- 1.6 mm ($^1/_{16}$ in) for calibrated sections with an inside diameter of 300 mm (12 in) or less
- 3.2 mm ($^1/_8$ in) for calibrated sections with an inside diameter greater than 300 mm (12 in)

Out-of-roundness shall be defined as the maximum internal diameter minus the minimum internal diameter. This shall be measured over the entire length of the calibrated section.

The roughness of the calibrated section interior surface shall not exceed 125 Tin of the Average Arithmetic Roughness Height (AARH) for uncoated sections (i.e., meter run) or 32 Tin AARH for coated sections (i.e., prover).

The calibrated section shall be provided with flange connections to allow visual inspection of all welded connections and interior surfaces. Connecting flanges within the calibrated section shall be tongue and groove and shall be drilled for dowel pins for accurate alignment.

Equipment and Components: The prover shall be provided with a permanently mounted stainless steel nameplate that includes the following information:

1. Manufacturer's name
2. Serial number
3. Prover design flow rate
4. Pressure/temperature rating
5. Hydrostatic test pressure
6. Calibration date
7. Calibration pressure
8. Base volume
9. Purchase order number

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4.2.4.2. Addition: Temperature Stability

If this system is not sheltered from the weather, insulation shall be provided.

4.2.4.5. Addition: Displacing Devices

An elastomer type sphere shall be used as described in this Section. At least one spare sphere shall be provided with this system.

4.2.4.6. Addition: Valves

The prover shall be provided with an electro-hydraulically operated two-position four-way valve. This valve shall have the following features:

- Control from the control panel
- A differential pressure indicator that verifies valve seal integrity
- A differential pressure instrument on the control panel for indication of seal integrity during prover operation

If the control panel is remotely located, skid-mounted controls for the two-position, four-way valve shall also include the following:

- A three-way selector switch with Local-Off-Remote positions.
- A two-way selector switch for valve positioning.
- Any local switches shall take precedence over remote controls.

4.2.4.8. Addition: Detectors

Mechanical sphere detection switches shall have no adjustable components.

4.2.6.3. New Paragraph

The diameter of sphere chamber ends shall be two pipe diameters greater than that of the calibrated section. Each chamber shall be provided with a safety blowdown valve. One chamber shall be equipped with a hinged, quick-opening closure. Access to the other chamber shall be achieved by the removal of a blind flange.

A rotating sphere-lifting davit mounted on the LACT unit skid shall be provided whenever the sphere diameter is 250 mm (10 in) or larger.

4.2.6.4. New Title: General Items

4.2.6.4. New Paragraph

Provers shall be provided with the following items:

1. Vent valves on the high points of the sphere chambers

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2. A thermal relief valve
3. Drain valves at all low points outside the calibrated section and on the sphere chambers
4. One pressure gauge and one temperature gauge at each end of the calibrated section
5. Permanent connections for field water draw calibration
6. Spheres, filling kit, sizing gauge and removal tools

4.2.7.4. Addition: Displacer Velocity

Sphere velocity shall be limited to 1.5 m/s (5 ft/s).

4.2.11. Modification: Calibrating Pipe Provers

The base volume of the prover shall be determined using the water draw calibration method.

4.2.11.2. Modification: Calibrating Bidirectional Provers by the Waterdraw Method

After determining the base volume, the water draw calibration shall be performed again using a reduced water flow rate to verify that no internal leaks exist.

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Process Analyzers

MP 32-P-06

July 1998

Scope

This Mobil Engineering Practice (MEP) covers requirements for the design, installation and testing of analyzers that are permanently installed outside a manned laboratory, together with associated components for process control, economy and monitoring safety or the environment.

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Table of Contents

Scope **1**

Table of Figures **8**

1. References **9**

1.1. MEPS–Mobil Engineering Practices 9

1.2. Mobil Data Sheets 9

1.3. API–American Petroleum Institute 9

1.4. ASME–American Society of Mechanical Engineers 9

1.5. ASTM–American Society for Testing and Material 10

1.6. NFPA–National Fire Protection Association 10

1.7. IEC–International Electrotechnical Commission 10

1.8. ISA–Instrument Society of America 10

2. General **11**

2.1. Data Sheets 11

2.2. Materials 11

2.3. Design 12

3. Documentation **12**

3.1. Approval Drawings 12

3.2. Manuals/Data Books 13

4. Acquisition Of Samples **13**

4.1. Sample Tap 13

4.2. Sample Transport System 15

4.3. Sample Return 20

4.4. Sample Conditioning System (SCS) 21

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5. Analyzer 22

6. Housing 22

6.1. Cabinet 22

6.2. Shelter 22

6.3. House 23

7. Utilities 23

7.1. Air and Nitrogen 23

7.2. Cooling Water 23

7.3. Atmospheric Vent Header 24

7.4. Steam 24

7.5. Calibration 24

7.6. Validation 24

7.7. Power 25

8. Safety 26

8.1. Temperature 26

8.2. Toxicity 26

8.3. Access 26

Appendix A: Data Sheet Instructions 27

1. Stream Analyzer Data Sheet T3206C01 27

1.1. Tag No: 27

1.2. Item 1 27

1.3. Item 2 27

1.4. Item 3 27

1.5. Item 4 28

1.6. Item 9 28

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1.7. Item 11 28
1.8. Items 11 and 13 28
1.9. Item 14 29
1.10. Item 16 29
1.11. Item 17 29
1.12. Item 18 29
1.13. Item 21 29
2. Stream Composition Data Sheet T3206C03 30
2.1. Item 1 30
2.2. Item 2 30
2.3. Item 3 30
2.4. Item 4 30
2.5. Item 5 31
2.6. Item 6 31
2.7. Item 7 31
Appendix B: Sample Conditioning System 32
1. Scope 32
2. General 32
2.1. Instruction Manuals 32
2.2. Nameplates 33
2.3. Other Requirements 33
3. System Design 34
3.1. Flow Restriction 34
3.2. Validation/Calibration Sample 34
3.3. Equipment Layout 34

3.4. Rotameters 34

4. Quality Assurance Requirements 35

4.1. Hydrostatic Testing 35

4.2. Leak Test 35

4.3. System Operating Test 35

Appendix C: Analyzers 37

1. Scope 37

2. Work By Others 37

3. Miscellaneous Requirements 37

3.1. Instruction Manuals 37

3.2. Nameplates 38

4. Design Requirements 38

4.1. Performance 38

4.2. Safety 39

4.3. Electrical 39

5. Quality Assurance Requirements 40

5.1. Test Requirements 40

5.2. Inspection Requirements 40

Appendix D: Analyzer House Details 42

1. Scope 42

2. General 42

3. Structural 42

3.1. Structural Data 42

3.2. Floors 43

3.3. Concrete Foundation or Floors 44

3.4. Openings 44
3.5. Equipment Support and Mounting 45
4. Environmental Control 45
4.1. Air Change Rate 45
4.2. Alarms 46
5. Electrical Requirements 46
5.1. Associated Equipment 47
5.2. Wiring 47
5.3. Wire Segregation 47
5.4. Power Distribution Panels 47
5.5. Receptacles 47
5.6. Lighting 47
5.7. Cable Tray and Conduit 48
5.8. Ground Wire Sizing 48
5.9. Termination Cabinets 48
5.10. Main Power 48
6. Piping and Tubing Requirements 49
6.1. Piping and Tubing 49
6.2. Steam Traps 50
6.3. Hazardous Materials 50
6.4. Materials 51
6.5. Other Requirements 51
7. Cylinder Rack Requirements 51
Appendix E: Package Subcontract 53
1. General 53

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2. Work by Others 53

3. Seller's Responsibilities 53

Table of Figures

Figure 1: Typical Sample Probe.....14

Figure 2: Typical Sample Transport System.....17

Figure 3: Typical Sample Transport System.....18

Figure 4: Typical Sample Transport System.....18

Figure 5: Sample Disposal System.....20

Figure 6: Alternative High-Flow Sample.....21

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1. References

The following publications form a part of this Practice. Unless otherwise specified herein, use the latest edition.

1.1. MEPS–Mobil Engineering Practices

MP 00-P-04	Winterizing & Heat Tracing
MP 00-P-10	Meteorological Data for Plant Design

1.2. Mobil Data Sheets

Mobil Data Sheets	Mobil Data Sheets Home Page
D3206C01	Process Analyzers - Documentation Requirements Sheet
I3206C01	Process Analyzers - Inspection & Testing Requirements Sheet
T3206C01	Process Analyzers - Stream Analyzers - Customary Units
T3206C02	Process Analyzers - Analyzers - Customary Units
T3206C03	Process Analyzers - Stream Composition - Customary Units
T3206M01	Process Analyzers - Stream Analyzers - Metric Units
T3206M02	Process Analyzers - Analyzers - Metric Units
T3206M03	Process Analyzers - Stream Composition - Metric Units

1.3. API–American Petroleum Institute

API TP 555	Process Analyzers First Edition

1.4. ASME–American Society of Mechanical Engineers

ASME B31.3	Process Piping

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1.5. ASTM–American Society for Testing and Material

ASTM D4177	Standard Practice for Automatic Sampling of Petroleum and Petroleum Products API Designation: MPMS Chapter 8.2
ASTM E84 REV A	Standard Test Method for Surface Burning Characteristics of Building Materials

1.6. NFPA–National Fire Protection Association

NFPA 496	Standard for Purged and Pressurized Enclosures for Electrical Equipment (National Fire Codes, vol. 7)
NFPA 497A	Recommended Practice for Classification of Class I Hazardous (Classified) Locations for Electrical Installations in Chemical Process Areas (National Fire Codes, vol. 11)

NOTE: Section 7 lists the requirements for a non-hazardous interior. Our shelters are usually designed to Zone/Div 2 standards.

1.7. IEC–International Electrotechnical Commission

IEC 1831/TR	A Guide to the Design and Installation of Online Analyzers Systems
IEC 1285	Industrial-Process-Control–Safety of Analyzer Houses

1.8. ISA–Instrument Society of America

ISA S5.1	Instrumentation Symbols and Identification R(1992)
ISA S5.4	Instrument Loop Diagrams
ISA S12.4	(WITHDRAWN) Instrument Purging for Reduction of Hazardous Area Classification
ISA S51.1	Process Instrumentation Terminology R(1993)

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2. General

The design, installation and testing of analyzers that are permanently installed outside a manned laboratory shall be in accordance with requirements of this MEP, unless superceded by more stringent local regulations.

- Drawing symbols shall conform to ISA S5.1.
- Analyzer house locations shall be shown on the main plot plan to ensure that an adequate area is provided for enclosures.
- Analyzers and associated equipment shall meet the requirements of applicable national and local codes. The contractor shall certify in writing that all of these requirements have been met. Any deviation from requirements shall be submitted to Mobil for approval prior to purchase and installation.
- When required by project specifications, analyzers and associated equipment shall be subject to seismic testing. The standards used for testing and the necessary certification shall be developed by the contractor and submitted to Mobil for approval.
- Analyzers shall be furnished in accordance with the project requirements. The contractor may propose additional or alternative analyzers or methods for Mobil approval.
- Analyzer installations shall be in accordance with API TP 555. Where words such as "preferred" and "majority use" occur, they shall be interpreted as "shall be."

2.1. Data Sheets

Analyzer Data Sheets (see the Mobil Data Sheets for this MEP) shall be completed by the contractor and vendor for Mobil approval.

- The contractor shall use these data sheets to transmit information to vendors.
- Pertinent information relating to the data sheets is given in Appendix A.
- Plant upset conditions and extremes shall be included in addition to normal process variations.

2.2. Materials

All materials shall be suitable for the sample stream and the surrounding atmosphere.

- Nonmetallic materials or low-melting alloys (except aluminum in cryogenic service) shall not be used in lines handling hydrocarbon or other flammable substances.
- Copper or copper-bearing alloys shall not be used in ammonia or H_2S service.

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2.3. Design

The sample system and analyzer shall be designed to recover automatically from upsets at the specified design limits. The analyzer need not maintain its specified accuracy outside the specified normal operating range.

- The analyzer systems supplier shall be responsible for the correct design and proper operation of the analyzer systems according to the drawings and specifications, and shall be held responsible for compliance with all specifications.
- The scope of such a package subcontract is given in Appendix E.
- It is the vendor's responsibility to ensure that all facilities, equipment and samples are available for checkout and testing to demonstrate that the equipment meets specifications.

3. Documentation

Loop drawings and proposed formats shall be in accordance with ISA S5.4 and shall contain all information listed therein as "necessary" or "desirable." The contractor's standard format may be used as a base provided that all data shown in ISA S5.4 are noted on sheets that have a similar format.

- A loop diagram showing all terminations and cable or piping identifications shall be prepared for each complete analyzer loop.
  - Each loop drawing shall identify all items interconnected in an analyzer signal circuit, including power supply terminals and computer terminals.
  - Loop diagrams shall be large enough so that the dense wiring interconnections are clearly shown.
- Interconnections between power supplies shall be shown on a separate schematic.

3.1. Approval Drawings

- At the inquiry stage, vendors shall provide preliminary drawings that shall include the locations in space orientation, size, description, function and specification of all services to which external connection shall be made.
- Electrical termination drawings shall also include the terminal numbers and terminal strip identification for every wire.
- Sample system schematics shall be included in the approval drawings.
- Every drawing shall include the relevant analyzers tag number(s).

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3.2. Manuals/Data Books

- The vendor shall supply complete documentation for operation and maintenance with the analyzer system. In addition to the copies requested in the order, one copy shall be shipped inside the analyzer, system or house.
- As-built drawings shall be supplied at the time of equipment completion and checkout.
- Each assembly drawing shall be associated with a complete parts list referring to all parts or subassemblies and each subassembly shall include a reference to the assembly that includes it. Parts data shall include the manufacturer's name and location, part number and description.
- Manuals shall include the following:
  - Inspection and test reports for the appropriate analyzer or system
  - Recommended spare parts list (for two years) for all repairable or replaceable components and equipment, including the manufacturer's name and address, part number and description
  - Principles of operation, start-up, maintenance and troubleshooting

4. Acquisition Of Samples

Wherever possible, samples shall be taken from single-phase regime locations.

A laboratory sample point shall be included in the analyzer system at an accessible point near the analyzer to ensure that the laboratory sample is fresh and comparable to the sample supplied to the analyzer. Acquisition of a laboratory sample shall not interfere with the continued operation of the onstream analyzer.

Where equipment can suffer permanent damage from failure of upstream control devices (e.g., pressure reducers, coolers), protective devices shall be included (e.g., relief valves, thermal switches).

4.1. Sample Tap

1. The sample tap through the first block valve shall conform to the process line specification.
2. Sample takeoff and return block valves shall be accessible from grade, platform or permanent ladder.
   a) Samples are run through the plant and in case of hazard the line shall be closed off at the sample point.
   b) Access to the sample point is a safety concern.

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3. Sample probes conforming to Figure 1 may be installed with any orientation on vertical or horizontal process lines.

4. Sample flow differential pressure shall not be derived across a control valve.

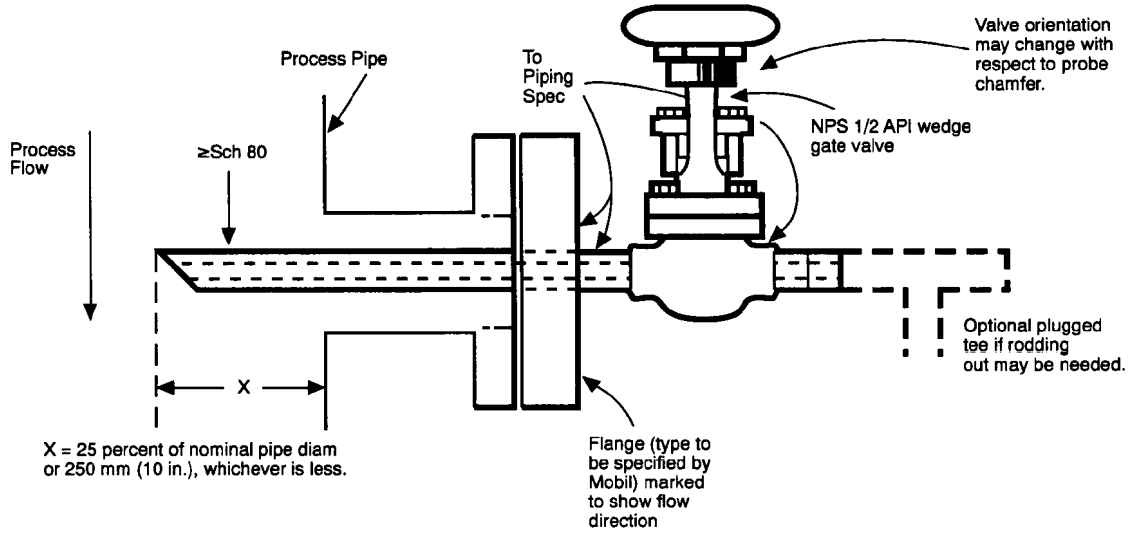
Process Pipe
To Piping Spec
Valve orientation may change with respect to probe chamfer.
NPS 1/2 API wedge gate valve
Process Flow
≥Sch 80
Optional plugged tee if rodding out may be needed.
X
X = 25 percent of nominal pipe diam or 250 mm (10 in.), whichever is less.
Flange (type to be specified by Mobil) marked to show flow direction

Figure 1: Typical Sample Probe

NOTE: Sample return connections may be a valved branch on the process line.

4.1.1. Order of Precedence

The order of precedence for obtaining differential pressure shall be:

1. Across a process pump
2. Across process equipment
3. From process to atmospheric pressure system (such as drain or sample recovery systems)
4. From process to flare line
5. Across an orifice plate with Mobil's approval
6. By installation of fast loop pump

4.1.2. Liquid and Vapor Samples

The sample takeoff probe shall conform to Figure 1 unless otherwise specified or agreed to by Mobil. Small probes require vibrational calculations to ensure that the probe cannot fail due to resonance effects. See ASTM D4177, Appendix X1.

Where the sample contains suspended solids, provision shall be made for rodding out the sample tap.

4.1.3. Vaporized Liquids and High-Pressure Gases

For liquids to be vaporized and for high-pressure gases, select one of the following:

1. Transport the liquid sample to the vicinity of the analyzer by means of a high-flowrate liquid bypass.
2. Use an insertion reducer, such as the Welker instrument valve, that has the pressure-reducing valve at the probe tip. The importance of the analysis shall be reviewed with Mobil to determine whether the probe shall be retractable with the process line in service.
3. Install a vaporizing reducer at the sample tap. The volume of liquid to be vaporized shall be calculated and the resultant delay time shall be documented.

4.2. Sample Transport System

Where analyzers provide input to closed control loops, the sample transport system shall be furnished with a low-flow alarm to warn when the sample is not flowing to the analyzer.

Flow alarms shall be resistant to false safe signals. For example, sample line solidification shall trigger the alarm.

4.2.1. Holdup

Total time for process sample to travel from sample tap to analyzer shall be less than 90 seconds unless otherwise specified on the Mobil Data Sheets for this MEP. Typically, 60 seconds is taken by the fast loop and 30 seconds by the sample conditioning system.

- Every sample transport system shall be fitted with a flow measuring device to show that the sample is updated.
- Each transport system shall be reviewed for the necessity of including a low-flow alarm.

4.2.2. Flushing

Facilities for flushing (or backflushing) the sample line and analyzer shall be provided as follows:

1. On all streams where the sample has a viscosity greater than 500 cP at 38°C (100°F)
2. Where solids are present or solidification is possible by reaction or polymerization
3. For corrosive and toxic services

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The flushing medium shall be injected immediately downstream of the sample takeoff point.

4.2.3. Liquid Sample Transport Systems

1. The sample circulating loop shown in Figure 2 or Figure 3 shall be used as a minimum basic design to transport liquid samples from a process line to the sample conditioning system.
2. When a pump is required in a liquid sample transport system, it shall be located as close to the sample tap as necessary to ensure at least 150 percent of the required pump net positive suction head (NPSH) under lowest process stream pressure conditions.
3. Filters shall be self-purging, designed to return solids to the process rather than accumulate them in the filter body.

4.2.4. Legend for Figures 2–4:

1. Sample tap (Figure 1)
2. Gate valve (transport line size or NPS $^1/_2$, whichever is larger)(Figure 1)
3. Pressure regulator–heat as required
4. Self-cleaning filter, with 100 mesh stainless steel screen, filter flow to the sample conditioning system
5. Y-type filter (100 mesh) or cartridge filter, minimum volume
6. Gate valves, line size
7. Rotameter (armored)
8. Needle or globe valve, line size
9. All liquid lines 6 mm ($^1/_4$ in) minimum inside diameter
10. Steam or electrically heat trace lines as required to maintain temperature
11. All lines 3.2 mm ($^1/_8$ in) minimum inside diameter

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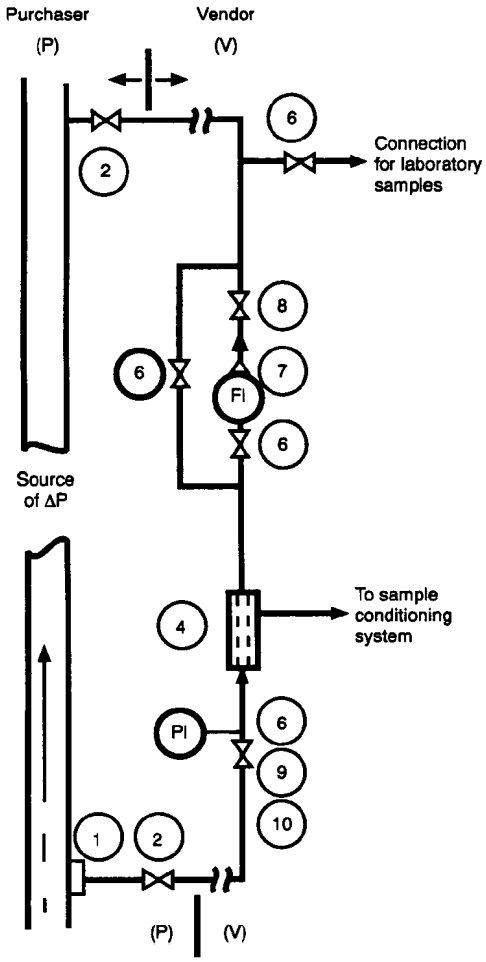

Figure 2: Typical Sample Transport System

NOTE: For all liquid samples and for vapor samples that cannot be safely vented. For nonlubricating liquid <1 cP at flowing conditions.

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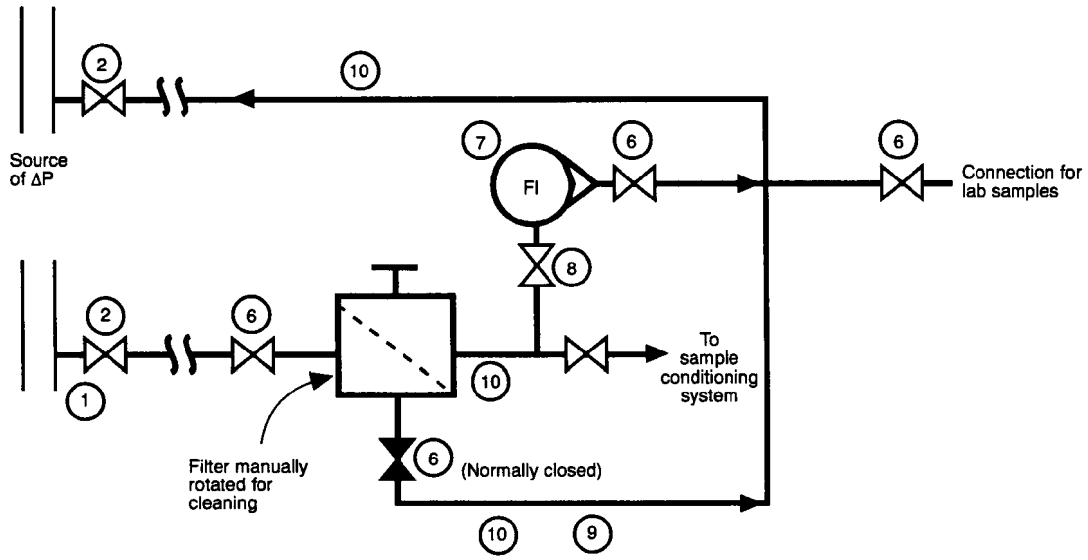

Figure 3: Typical Sample Transport System

NOTE: For all liquid samples and for vapor samples that cannot be safely vented. For lubricating liquid >1 cP at flowing conditions.

4.2.5. Vapor Sample Transport Systems

Figure 4 shall be used as a minimum basic design. Vent lines subject to condensation of moisture and/or hydrocarbons shall be steam traced or electrically traced and shall slope to a low-point drain. The pressure of vapor shall be reduced to a minimum as close as possible to the sample tap.

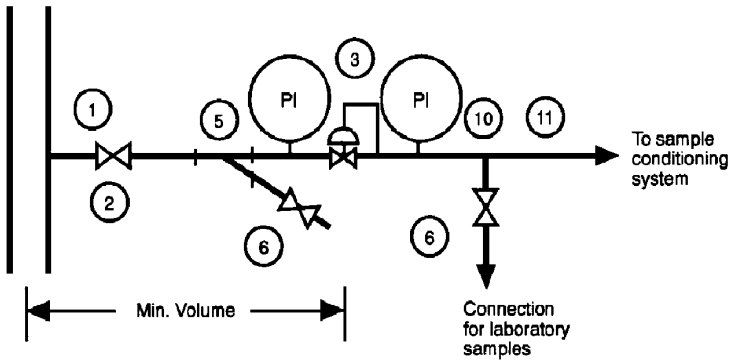

Figure 4: Typical Sample Transport System

NOTE: A Welker instrument valve is also acceptable.

4.2.6. Piping and Tubing

Transport piping before filtration shall conform to the process pipe material specification. Piping after filtration shall be Type 304 stainless steel, minimum.

4.2.6.1. Specifications

- Piping shall be in accordance with ASME B31.3.
- Piping shall be seamless. The minimum wall thickness shall be as follows:

Material	Size Range	Min Thickness
Pipe: Carbon Steel	NPS $^1/_2$ and larger	Schedule 80
Alloy	NPS $^1/_2$ and larger	Schedule 40

NOTE: NPS = nominal pipe size, inches.

- Liquid fast loops shall be NPS $^1/_2$. Other sizes may be used with Mobil approval.
- Vapor transport lines shall be $^1/_4$ in or $^3/_8$ in O.D. Other sizes may be used with Mobil approval.
- All components subject to process line conditions shall conform to the process line service classification.

4.2.6.2. Joints

1. Piping shall use welded or flanged joints.
2. Pipe or tubing runs containing flammable or toxic materials shall have only welded joints.
3. Threaded terminations in tubing systems shall not be seal welded. Tubing shall use compression fittings that conform to site or project standards and a single length of welded or drawn tubing shall be used.

4.2.6.3. Cleaning

- Shop-fabricated piping shall be cleaned in the shop prior to shipment. All other piping shall be cleaned prior to operation of the equipment.
- Piping shall be cleaned by steam, air or water flushing and, if necessary, mechanical cleaning.

4.2.6.4. Temperature

- Where the fluid temperature is below -29°C (-20°F), piping material specification shall be offered to Mobil for approval.

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4.2.6.5. Tracing

- If a sampling line needs to be heated, a heat-traced bundle of Type 316 stainless steel trace tubing, DEKORON or equal, shall be provided. Requirements for light tracing or heavy tracing shall be agreed with Mobil before purchase (for vapors or samples vaporized at takeoff point).
- To prevent polymerization where active compounds (such as butadiene) are present, heating for vapor samples shall be sufficient only to keep the sample 10°C (18°F) above its dew point.

4.2.6.6. Pumps

Pressure casing parts of sampling pumps that handle flammable or toxic liquids shall be of carbon steel or alloy steel.

4.3. Sample Return

Spent sample from analyzers shall, wherever possible, be returned directly to process. A sample disposal system shall be furnished when a liquid sample is not returned directly to process. One such system can serve each analyzer house or other concentration of analyzers. Figure 5 or 6 shall be used as a minimum basic design for the sample disposal system.

Each sample return point shall be equipped with a check valve and block valve.

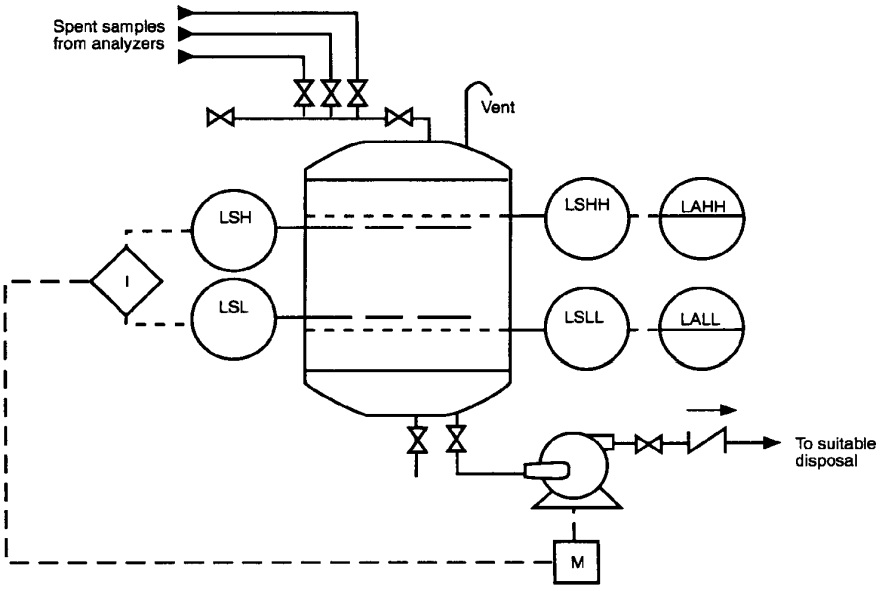

Figure 5: Sample Disposal System

NOTES:

1. Time to fill from LSL to LSH shall be 20 minutes.
2. LSL to LALL and LSH to LAHH should be 10 minutes.

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3. Minimum pump design capacity equals 200 percent of sample in-flow rate.
4. Pump is removable for service.

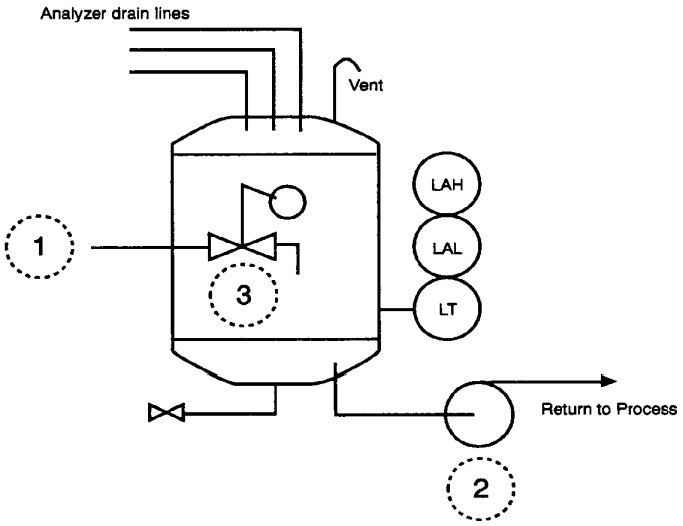

Figure 6: Alternative High-Flow Sample

NOTES:

1. From analyzer fast loop.
2. Pump runs continuously at flow rate greater than two times total analyzer drain.
3. Float valve maintains level.

4.4. Sample Conditioning System (SCS)

Requirements for the sample conditioning system (SCS) are contained in Appendix B.

- The SCS shall be designed to accommodate plant upsets. For example, any stream that normally contains small amounts of suspended water will at some time carry large amounts of water up to 100 percent. The SCS must therefore protect an analyzer that is rendered inoperative by 100 percent water, perhaps by interrupting sample flow to the analyzer during the excursion.
- All components shall be minimum maintenance (e.g., self-cleaning filters).
- All material in contact with the process sample after filtration shall be stainless steel, unless a special material is required for the process or utility fluids handled.
- Tubing compression-fitting ferrules shall have a hardness greater than the tubing.
- Vendor proposals to use materials or thicknesses alternative to those specified shall be submitted to the purchaser for approval by Mobil.

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5. Analyzer

The requirements for analyzers are contained in Appendix C.

6. Housing

Analyzers shall be protected from direct sun or rain. Where ambient conditions lie outside the analyzer specification, climate control is required.

Analyzer case requirements are included in Appendix C.

6.1. Cabinet

- Valves and switches required to isolate the analyzers shall be mounted outside the cabinet.
- Pressure regulation devices and flow restrictors shall be mounted outside the cabinet, as far as practicable.
- Any pressure relief device or analyzer vent shall discharge outside the cabinet and any surrounding building.
- Pipes, tubing and cables shall pass through the sidewalls into the cabinet and be weather sealed. Cable entry sealing shall conform to electrical safety requirements.
- There shall be sufficient space between the cabinet and its contents to permit any access necessary for maintenance.
- Where flow, pressure or other indications are included, shatterproof windows shall be provided in the cabinet to permit observation when the doors are closed.
- Props or stays shall be provided to immobilize doors in the open position.

6.2. Shelter

To ensure adequate natural ventilation of an analyzer shelter:

- The shelter shall be completely open on one length (that is, it shall have at least one long wall absent).
- There shall be a clearance of ≥150 mm (6 in) between roof and walls and between base and walls to permit free circulation of air around all surfaces.

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6.3. House

The full specification for an analyzer house is given in Appendix D.

7. Utilities

Required utility connections shall be as follows:

- A minimum NPS $^{3}/_{4}$ header shall be provided for each utility (steam, air, cooling water, etc.) with a shutoff valve outside the shelter or cubicle.
- Headers shall terminate with a valve and plug to permit later extension to other users.
- One additional accessible valved and plugged outlet shall be provided on each header inside the shelter or cubicle to facilitate temporary connections.
- Headers shall generally be carbon steel, except for the instrument air header which shall be galvanized.
- Polymers or low-melting-point metals or alloys shall not be used on lines carrying toxic or flammable fluids.
- Each user shall have an individual shutoff valve.
- Lines in which condensation can occur (steam, air, vent) shall slope to a low point.
- Aromatic-solvent-resistant sheathing is required for copper tubing used on cold service.
- Tubing connected to cylinders shall include a pigtail to allow convenient replacement of cylinders.
- Winterization and heat tracing shall be installed in accordance with MP 00-P-04.

7.1. Air and Nitrogen

Failure of a single filter/pressure reducer (air set) shall result in the failure of not more than one analyzer.

NOTE: Connection of nitrogen into an analyzer enclosure requires the addition of a low-oxygen alarm system.

7.2. Cooling Water

The cooling water supply header shall have a strainer and drain valve.

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7.3. Atmospheric Vent Header

The external stack (removable for shipment) shall be designed to minimize the effect of wind and rain on the analyzers.

Drain and vent headers shall be Schedule 40 carbon steel pipe unless otherwise approved by Mobil.

7.4. Steam

- Traps shall be provided outside the housing for all steam-traced inlet sample lines as well as all steam users.
- For personnel safety and climate control, any steam lines shall be routed outside the housing to the maximum extent.
- The supply header shall have a strainer with blowdown valve and a steam trap.
- Any condensate return header shall have an outlet check valve.
  - Each parallel user shall have an individual steam trap.
  - All steam lines shall be insulated for personnel protection and to prevent heat loss.

7.5. Calibration

Calibration gas or liquid shall contain components in the same proportions predicted to be present in the stream to be analyzed, except that unstable components shall be omitted.

Calibration and validation samples arriving on site shall first be taken to the lab for analysis, whether or not they have a certificate of analysis. They shall not be used on an analyzer until the lab has provided an analysis reconciled with any external certificate.

7.6. Validation

A validation system shall be provided to allow remotely controlled injection of a known sample into the analyzer. The resulting analyzer output shall be compared with the (stored) expected result and statistical quality control methods shall be used to determine whether the analyzer is operating in (statistical) control.

7.6.1. Validation System Hardware

Validation system hardware requirements include:

- Containers shall hold sample volume sufficient for three to six months with no possibility of degradation.

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- The amount of sample remaining (the pressure of a vapor sample or the mass or level of a liquid sample) shall be indicated.
- Minimize sample waste and purging.
- Control temperature of sample, as appropriate.
- Inject sample with no cross-contamination.
- Refill from process line without interrupting an analysis.
- If pressurization is required to transport the sample to the analyzer, it shall not affect the composition of the sample.
- Sample container shall be transportable to lab for checking.

7.6.2. Validation System Software

Validation system software requirements include:

- Storage and operating capacity for up to one year of data for 60 analyzers.
- Store lab analysis of the validation sample (VS).
- Inject the VS into the analyzer on demand. Limit injections to one per shift. Log the time and date of the VS injection.
- Compare stored lab analysis with analyzer reading on the VS.
- Generate a lab-minus-analyzer control chart on screen and printer for each analyzer output.
- Separate alarm contact for an "OK/NOT OK" comparison (difference within control limits).
- Monitor the amount of sample remaining.
- Predict the need for sample replenishing based on current usage and amount remaining.
- Warn if the analyzer reading is not stable when requested to refill from the process line.

7.7. Power

Process control analyzers do not require uninterruptible power supplies (UPS). Analyzers for environmental and safety purposes may need a UPS depending on the mandatory local service requirements.

7.7.1. Grounding

Signal ground shall be separate from the chassis/case ground, and shall be bonded to the site instrument-grounding system at only one point. Cable shields shall be grounded at only one end. Power ground shall be separate from the chassis/case safety ground up to a common point at the ground rod(s). a separate ground system is required for any IS equipment ground.

8. Safety

8.1. Temperature

Equipment surfaces operating above 60°C (140°F) and located within 0.9 m (3 ft) horizontally of a normal access, walkway or work area shall be insulated to protect personnel. Where insulation is not possible, personnel shall be protected by open guards, shields or railings.

8.2. Toxicity

The short term exposure limits for most gases and vapors is lower than their lower explosive limit and personnel protection requirements may be more stringent than equipment protection requirements. See Section 4.2 of Appendix D for alarms for toxicity and explosiveness; see Mobil Material Safety Data Bulletins for toxicity information.

8.3. Access

Accessibility for maintenance shall be a prime consideration in the design of the analyzer systems and layout of the packages. The analyzer systems shall be designed so that failure or removal of any component normally requiring service does not interfere with the operation of any other component.

Clearance between shelter or house floor and any overhead obstruction in any walkway shall be 2 m ($6^1/_2$ ft) or greater.

There shall be no sharp points or protrusions in areas where access may be needed for maintenance or operation.

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Appendix A: Data Sheet Instructions

NOTE: T3206C01 (see the Mobil Data Sheets for this MEP) in its present form, may not be entirely suitable for a particular analyzer. However, it is a good starting point and can be modified to specifically describe a unique requirement.

1. Stream Analyzer Data Sheet T3206C01

1.1. Tag No:

Use tag numbers such as ARxxx and not A(H_2S)Rxxx because:

1. The latter is a mixture of method and component.
2. A given analysis may be achieved by a variety of methods. For example, H_2S may be measured by chromatograph, UV, IR, wet chemical or solid state methods.
3. It is contrary to ISA S5.1.
4. You can use the "A" for density, viscosity, conductivity and any other analytical parameter.

1.2. Item 1

Identify as straight run (SR), naphtha, fluid catalytic cracker (FCC), gas oil, etc. This indicates composition and stability.

1.3. Item 2

List control action to be taken as a result of a change in analyzer reading.

1.4. Item 3

Identify as 90 percent EP, 10 percent IBP, RVP, pour, flash, etc. (List relevant lab method such as ASTM at Item 8.)

1.5. Item 4

Select output range so that the span is a convenient multiple of two and five units and the span is ≥50 times the analyzer repeatability.

1.6. Item 9

If the analyzer is expected to control, then the total delays of the fast loop, sample conditioning system and analyzer shall be less than $^1/_5$ of the time constant of the controlled variable.

Thus, analyzers controlling blending into tank cars shall be very fast (just a few seconds total delay) while an analyzer resetting a temperature controller has only to update the model, which may change with crude switches once every two days.

1.7. Item 11

Identify as stabilizer reflux accumulator, stripper bottoms, etc. This indicates possible contamination and may lead to suggestions for a more suitable sampling point. It is helpful to include the process line number.

1.8. Items 11 and 13

- Show the maximum and minimum that can be expected from the process under upset conditions. The analyzer shall keep functioning when the process is upset, even though the reading may not be within the accuracy specification, but it must recover after the upset.
- Conditions at the sample source and return point influence the need for pressure regulators, sample pumps, extra coolers, etc. Return all bypass streams to a vent header or to the process. If no streams are to be returned, this fact shall be stated. However, consideration shall be given to the possible pollution of air or water if the sample is not returned. Sample transport-line size and calculated flowrates shall be specified by the system vendor to meet required response times for effective process operation.
- Differential pressure is necessary to drive a fast loop and cannot be calculated by subtracting normal return pressure from minimum source pressure.
- The source of differential pressure to drive the sample transport system shall be selected in the order described in Section 4.1.1 of this MEP.

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1.9. Item 14

Give viscosities and densities at two different temperatures so that the fast-loop designer can interpolate or extrapolate to other conditions.

1.10. Item 16

Process line data shall include all parameters that affect the sample, including all impurities and contaminants that may occur under upset conditions. For example, for gas from a caustic scrubber that normally contains small suspended droplets of spent caustic solution and on rare occasions slugs of spent caustic, line data shall read "0.1 percent w/v 10 percent NaOH soln, plus rare 100 percent slugs."

1.11. Item 17

Ambient temperature at the analyzer or possible changes of state due to temperature and pressure changes shall affect the need for sample heating and/or sample cooling. Periodic heavy rain or high winds (weather extremes) may necessitate shelter for the analyzer or for service personnel even in mild climates. Heat from adjacent process equipment shall not be overlooked in choosing a location and this information shall be noted on the data sheet.

All heat-producing equipment used in classified areas is marked to indicate a maximum surface temperature, identified by a number or "T" rating. This temperature shall be lower than the ignition temperature of any specific gas present in that particular area.

The required electrical area classification information, with "T" rating, may influence the choice of location. Most analyzers are provided with explosion-proof housings; most receivers are not. The area classification shall be considered for all instruments.

1.12. Item 18

All of the utilities called for may not be needed for a given installation. If utility requirements are accurately known, no other data need be listed. If utility requirements are not accurately known, complete data shall be provided. Possible substitutions shall not be overlooked. For example, when instrument air is not available, addition of a small filter and drier may permit the use of plant air.

1.13. Item 21

The distance over which analyzer signals are to be transmitted need not be given precisely. If the distance is extreme (over 300 m [1000 ft]), it may influence system design. Mobil prefers isolated electric current signal transmission. Voltage signal transmission shall not be used without prior approval by Mobil. Digital and/or optical

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data transmission may be required from microprocessor-based systems and shall be in a format compatible with the distributed control system (DCS).

2. Stream Composition Data Sheet T3206C03

T3206C03 (see the Mobil Data Sheets for this MEP) is intended to supplement and shall be attached to T3206C01 (see the Mobil Data Sheets for this MEP). Use only one stream per chromatograph for control. Any exception is subject to Mobil approval. Since the data are intended to furnish a vendor with all the information necessary to specify a fully suitable chromatograph for each application, it may be desirable to attach memoranda or sketches.

2.1. Item 1

Check whether the sample is liquid or vapor. If liquid, give the bubble point as a guide to whether vaporization is desirable. If vapor, give the dew point as a guide to the minimum temperature that must be maintained in the sample system.

- Generally, samples that can be kept in the liquid phase at the analyzer oven temperature and at a practical pressure shall not be vaporized.
- However, liquids that can be completely vaporized at 120°C (250°F) may be vaporized if this seems preferable.
- Avoid vaporization where solids may precipitate or when decomposition/polymerization may take place.

2.2. Item 2

In addition to the average stream composition expected, list under "Minimum" and "Maximum" the stream composition when the key component is at minimum and maximum levels. All trace components and physical properties shall be listed on T3206C01 (see the Mobil Data Sheets for this MEP). A laboratory analysis of the process stream is preferable to a theoretical estimate of composition.

2.3. Item 3

Outputs may be individual stream components, one or more components grouped or summed together, a ratio or a difference expressed as a single output.

2.4. Item 4

The response time shall be less than one-tenth of the response time of the loop to be controlled. For example, where an analyzer output is cascaded into a temperature control

loop, the response time of the loop is the rate of drift of composition at constant temperature. Response times between $^1/_{10}$ and $^1/_3$ are subject to Mobil approval.

2.5. Item 5

Normalization shall be provided where the detector is sensitive to 99 percent or more of components normally present and all components pass through the detector during a normal analysis. With the same detector capability, normalization shall be offered as an option as Nominal Stream 2.

2.6. Item 6

Helium is the typical carrier gas in the United States. However, other gases (hydrogen, argon, nitrogen) may be used where desirable for a particular analysis or where helium is not available. All microprocessor-based programmers can perform both positive and negative peak calculations.

2.7. Item 7

Each chromatograph shall be capable of producing a chromatogram. Other features (trend recording of peaks, bar charts, etc.) shall be specified. The analyzer shall provide these features internally or in conjunction with a DCS or a host computer.

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Appendix B: Sample Conditioning System

1. Scope

This Appendix is for sample conditioning systems (SCS) installed to introduce samples into an analyzer.

The SCS shall be supplied by an experienced specialist supplier who may be either an analyzer vendor or an analyzer specialist systems company.

2. General

The vendor shall submit a complete, detailed description of each proposed sampling system for Mobil approval prior to purchase. This description shall be provided in both English and the language of the country where the analyzer is to be installed. Standard instrumentation symbols, as specified in ISA S5.1, shall be used on all drawings.

- All sample system designs shall be reviewed in detail by owner because sample systems have proved to be the major cause of analyzer unreliability.
- The sample conditioning system shall be quoted separately.
- All documents shall be identified by the tag number, serial number, purchase order number and vendor's reference number.
- The vendor shall supply a recommended spare parts list suitable for two years of operation.

2.1. Instruction Manuals

All of the instruction manuals requested in the inquiry shall contain the following:

- Full information on principles of operation, installation, startup, maintenance and troubleshooting
- Assembly drawings
- Diagrams for sample schematics
- Electrical circuits

- Interconnections
- Spare part locations and installation
- Bills of material showing manufacturer's part numbers for all major pieces of equipment

Inspection and test data shall be included. All material irrelevant to the equipment supplied shall be scored through, deleted or omitted.

- All designations, labels and terminal numbering in the instruction manuals shall correspond exactly to the sample system supplied.
- One additional copy of the instruction manual shall be packed with the system.

2.2. Nameplates

1. A stainless steel nameplate shall be attached permanently to the sample system. Adhesive mounting shall not be accepted.
2. The nameplate shall be stamped or engraved with the following information:
   a) Tag number
   b) Serial number
   c) Purchase order number
   d) Vendor's reference number
3. Where accessory items are furnished separately, they shall be identified with the same information by an identical tag firmly wired to the accessory.
4. In addition, the following information shall be supplied on a permanently attached nameplate on the sample system or housing as applicable:
   a) Model number
   b) Minimum/maximum process pressure and temperature
   c) Sample flowrate, ambient limits, power requirements (Volts AC, Hz) and consumption (VA)
   d) Materials of components in contact with the sample

2.3. Other Requirements

- The manufacturer shall offer training of operations and service personnel with the required daily rate.
- The manufacturer shall state the calculated and historical mean time between failure (MTBF) and mean time to repair (MTTR) of the major system components.

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- Materials and components shall be consistent with the remainder of the project and site. A list of exceptions for proprietary equipment shall be included in the proposal.

3. System Design

3.1. Flow Restriction

For a toxic or flammable gas supply to an analyzer in an enclosure (e.g., hydrogen carrier gas for chromatographs), a restrictor, automatic cutoff or excess flow valve with a maximum flow of two times normal shall be furnished between the supply regulator and the analyzer. See Appendix D for shelter requirements.

3.2. Validation/Calibration Sample

The system vendor shall furnish all equipment necessary for the introduction of any calibration samples. The design and layout of equipment and piping shall satisfy Section 7.6 of this MEP.

3.3. Equipment Layout

Flanges or other removable connections shall be provided throughout the system as necessary for maintenance. Normal replacement of consumable items such as coalescers, filters, etc. shall not require system shutdown or removal of other components. The vendor's proposed layouts shall be submitted to the purchaser for review by Mobil.

3.4. Rotameters

- Rotameters shall be the metal tube type except that the glass tube enclosed type may be used if the fluid is air, inert gas or water with pressure below 345 kPa gauge (50 psig).
- When flowrates are lower than can be metered with the metal tube, a glass tube enclosed in a high-pressure gauge glass (flat-glass type) shall be used.
- Where space or layout considerations do not allow the use of such gauge-glass enclosures, the glass-tube type is acceptable with other types of shielding for personnel protection as approved by Mobil.
- End connections smaller than NPS $^1/_2$ shall be internal taper thread connections.
- Manufacturer's standard tube and float shall be used where possible with normal flowrate of 60–80 percent of capacity.

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- Meter factor shall be included on the nameplate.

4. Quality Assurance Requirements

4.1. Hydrostatic Testing

- All piping shall be hydrostatically tested at 1.5 times the design pressure.
- Piping systems in vacuum service shall be tested to 100 kPa gauge (15 psig).
- Austenitic stainless steel piping and tubing shall be tested and flushed with water with less than 500 ppm (500 mg/kg) chlorides. Potable water will meet this requirement. The piping and tubing shall be drained immediately after flushing and then dried by blowing with air.

4.2. Leak Test

A containment leakage test shall be conducted on the entire system at the specified design pressure. Maximum permissible leakage rates are as follows:

- Gas Systems: 5 percent change in pressure per hour.
- Liquid Systems: No visible leakage.

4.3. System Operating Test

- A factory test is required of all systems. The factory test shall be an operating test and it is the vendor's responsibility to provide all facilities required to demonstrate the system in accordance with the purchase order, this specification and the Mobil Data Sheets for this MEP.
- The test procedure shall be offered to Mobil for approval before placement of order.
- Mobil shall be given 10 working days notice of readiness for inspection. The equipment shall be held to await the availability of Mobil or a designated representative.
- The system test shall be performed at the temperatures and pressures given in the specification and with a fluid of similar properties (viscosity, vapor pressure, etc.) to the process sample.
- Complete factory data shall be given to the inspector at the time of inspection.
- If the factory test is not run at the specified voltage and frequency, the suitability of the equipment for the specified voltage and frequency shall be established by nameplate data of equipment components or certified by the equipment component manufacturers.

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Appendix C: Analyzers

1. Scope

This Appendix is for permanently installed analyzers as applied to process stream, safety and environmental (compliance monitoring) measurements.

2. Work By Others

Items listed below shall be furnished by others or form part of a separate contract. They are not the responsibility of the analyzer vendor under this document.

- Piping and wiring to and from the analyzer
- Analyzer walk-in shelter
- Placement and location of analyzer

3. Miscellaneous Requirements

- All documents shall be identified by the tag number, serial number, purchase order number and vendor's reference number.
- The vendor shall supply a recommended spare parts list suitable for two years of operation. Where more than one analyzer is offered, the spare parts lists shall be consolidated to avoid unnecessary duplication.
- The manufacturer shall describe with its offer any parameters known to interfere with the determination of the specified parameter.
- All terminals, terminal blocks and wires shall be identified.

3.1. Instruction Manuals

- All of the instruction manuals requested in the inquiry shall include full information on principles of operation, installation, startup, maintenance and troubleshooting, as

well as drawings and/or diagrams for sample schematics, electrical circuits, interconnections, spare part locations and installation.

- Calibration curve, inspection and test data shall be included. All material irrelevant to the model supplied shall be scored through, deleted or omitted.
- All designations, labels and terminal numbering in the instruction manuals shall correspond exactly to the analyzer supplied.
- One additional copy of the instruction manual shall be packed with the analyzer.

3.2. Nameplates

1. A stainless steel nameplate shall be attached permanently to the sample system. Adhesive mounting shall not be accepted.
2. The nameplate shall be stamped or engraved with the following information:
   a) Tag number
   b) Serial number
   c) Purchase order number
   d) Vendor's reference number
3. Where accessory items are furnished separately, they shall be identified with the same information by an identical tag firmly wired to the accessory.
4. In addition, the following information shall be supplied on a permanently attached nameplate on the analyzer housing:
   a) Model number
   b) Minimum/maximum process pressure and temperature
   c) Sample flowrate, ambient limits, power requirements (Volts AC, Hz) and consumption (VA)
   d) Materials of components in contact with the sample

4. Design Requirements

4.1. Performance

Per the definitions of ISA S51.1, the following performance specifications shall apply to the design conditions as stated in the individual analyzer data sheet (see the Mobil Data Sheets for this MEP):

1. Accuracy rating shall be ±1 percent of span or better.
2. Reproducibility shall be ±0.5 percent of span or better.
3. Dead band (sensitivity) shall be 0.3 percent of span or better.
4. The vendor shall describe in the offer the dead time and the 63 percent time constants of the analyzer to both increase and decrease in value.
5. Drift at midpoint of normal operation shall be less than 5 percent of output span per week.
6. Compensation.

The analyzer system operation shall be compensated so that accuracy is not compromised as a result of:

1. Ambient or sample temperature fluctuations
2. Barometric or sample pressure changes

A proven reliable internal normalization may replace calibration/validation sample.

4.2. Safety

The analyzer shall revert to a safe condition during a power loss and shall recover automatically when power is restored. Output shall be inhibited and an alarm provided until the analyzer is operating within its control limits.

- Cases depending on air purge dilution of hazardous material shall be protected by low-flow contacts on purge exit from the case to give an alarm for type Y or Z purge and power cutoff for type X purge.

  NOTE: These requirements are deliberately more restrictive than NFPA 496 and ISA S12.4.

- Bypasses used for calibration checks or maintenance shall be visually alarmed.
- In addition, bypasses for analyzers in safety or environmental monitoring services shall be audibly annunciated.

4.3. Electrical

Except for auxiliaries such as pumps, heaters, valves, etc., the analyzer supply voltage shall be 120 or 230 Volts AC ±10 percent and 50 or 60 Hz ±1, depending on location. If more stringent power specifications or protection from normal power transients are required, analyzers shall be furnished with appropriate AC power regulation.

Outputs for process control shall be directly proportional to the calibrated span.

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5. Quality Assurance Requirements

5.1. Test Requirements

- A factory test is required for all analyzers.
- It shall be the manufacturer's responsibility to provide all materials and equipment to factory test the operation of the analyzer(s) per the test procedure in ISA S51.1, Section 5.
- In addition to the preceding and the manufacturer's standard tests, the following shall be demonstrated:

  a) Stability of the analyzer over an eight-hour period

  b) Freedom from interference of any parameter so listed in the specification sheets

  c) Repeatability measured from the dimension of the band that contains 99 percent of the results obtained in 100 cycles of a cyclic analyzer or 100 time constants of a continuous analyzer

  d) Control charts demonstrating operation of the analyzer in control shall be attached to the instruction and maintenance manual

  e) Analyzer runs within its control limits on the voltage and frequency expected at site

5.2. Inspection Requirements

The manufacturer shall allow Mobil or Mobil's agent to inspect final assembly and packaging or any prior phase of assembly, if requested.

5.2.1. Notification Requirements

The manufacturer shall give a notice of 10 working days to Mobil or Mobil's agent prior to reaching the test and inspection points identified above.

5.2.2. Documentation Requirements

Documentation shall be supplied that is normally provided by the manufacturer and, in addition, as required by this Appendix, this Practice and/or the individual analyzer data sheets (see the Mobil Data Sheets for this MEP).

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5.2.3. Chromatograph Drawings

Drawings for chromatograph valve and column configurations shall include a chronological series of diagrams of each combination used for the analysis, with the beginning and end times of the combination.

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Appendix D: Analyzer House Details

1. Scope

This Appendix covers constructed analyzer houses that contain one or more analyzers in an enclosure with sufficient space to maintain the equipment with the door(s) closed. The houses are designed to protect the equipment against explosion hazard resulting from flammable materials released internally or present in the surrounding atmosphere.

2. General

The analyzer house shall be a self-contained prefabricated building of self-extinguishing construction that is suitable for service in the specified environmental conditions, weather conditions and electrical area classification.

- All analyzers and components shall be installed, wired and piped by a Mobil-approved analyzer system vendor (ASV).
- No field work shall be done inside the analyzer house; all field connections shall be on the outside.
- The house shall be suitable for installation on a raised concrete slab at the job site. The ASV is to design, fabricate and completely assemble the analyzer building or provide design specifications for fabrication and assembly by others while retaining control and responsibility.

Building foundation dimensions, structural weight, bolting patterns, drainage and other foundation requirements shall be determined and specified by the ASV.

The ASV shall specify how houses are to be lifted, transported and set in place.

3. Structural

3.1. Structural Data

- Structural load-bearing materials shall be metal. After any welding, minimum treatment shall be to blast metal-bright and prime.

- Load-bearing members shall be included in walls and along the internal apex of the roof.
- All exposed surfaces shall have a flame-spread classification less than 25 per ASTM E84 REV A.
- Walls and roof shall be double skinned, have an insulation value greater than or equal to R15 and shall be puncture proof both externally and internally.
- Nonmetallic walls shall be sufficiently conductive to avoid sparking from static electricity generated by local climatic conditions.

3.1.1. Space Requirements

Each building shall be designed with space, utilities, terminals and all facilities to accommodate one additional analyzer or shall be designed with a 15 percent excess of each commodity, whichever is greater.

Space for one additional analyzer is defined as 4 ft wide by the full height of a wall.

3.1.2. Maintenance Access

The maintenance aisle shall be at least 3 ft wide for easy maintenance and testing.

3.1.3. Emergency Exit Light

An emergency exit light is not required if the emergency exit door is visible from all parts of the interior.

3.2. Floors

- The finished floor of any shelter shall not be less than 150 mm (6 in) above adjoining grade. Drainage slope to a single drain hub shall be provided to prevent the accumulation of liquids. All drain connections shall have a minimum 150 mm (6 in) deep seal to prevent vapor backflow.
- False ceilings and floors shall not be used in analyzer houses.
- Mobil shall specify if the shelter floor is to be integral with the shelter or if the concrete pad is to be used as the finished floor.
- The base frame and any floor shall be integral with the shelter. If included, the floor shall be a minimum of 4.75 mm ($^{3}/_{16}$ in) thick self-draining diamond-tread steel plate or other sturdy non-slip material. The base frame shall be made of 150 mm (6 in) high steel channels and/or I-beams. The joints between the sidewalls and the base shall be sealed. The perimeter of the base frame shall totally enclose and isolate the air space under the house floor after the shelter is set in place with grout.

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3.3. Concrete Foundation or Floors

The analyzer shelter shall be set and bolted to a concrete pad installed by others.

- The concrete foundation pad may serve as the finished shelter floor on Mobil approval.
- The concrete pad shall be a minimum of 150 mm (6 in) above the adjoining grade level and shall have a concrete pad extension outside each door entrance.
- The concrete pad shall be sized to match the exterior dimensions of the shelter. Further extensions shall be provided as appropriate for HVAC equipment and sample system access.
- The pad shall have a drain with a cover that is flush with the concrete. The drain with its 150 mm (6 in) vapor seal is to be piped to the exterior of the pad.
- The inside base perimeter of the house shall be grouted to the pad.

3.4. Openings

All openings in buildings for passage of connections to equipment shall be flashed and caulked to be weathertight. Caulking shall be hydrocarbon-resistant butyl rubber sealant or equal.

3.4.1. Doors/Windows

Access doors shall be of nonfolding construction and open outward with stainless steel panic-bar hardware, closer hardware and locks and shall have sealed windows.

- One key shall pass all locks.
- The main door shall carry a nameplate showing the house number and the tag numbers of the included analyzers in letters 12.5–25 mm ($^1/_2$–1 in) high.
- The doors shall be mounted with a minimum of three stainless steel hinges and be equipped with safety latch and pneumatic door closer.
- Buildings larger than 6 m^2 (64 ft^2) shall have one door at each end of the shelter.
- It shall be possible to remove all analyzers through the main entrance doorway without disassembly.

Windows are to be less than 0.2 m^2 (2 ft^2) and shall be made of laminated safety glass resistant to a 7 kPa (1 psi) force acting inward or outward.

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3.5. Equipment Support and Mounting

Equipment shall be mounted on a freestanding framework or load-bearing wall supports.

4. Environmental Control

NOTE: The short term exposure limits for most gases and vapors is lower than their lower explosive limit and personnel protection requirements may be more stringent than equipment protection requirements.

- Forced ventilation is required for the totally closed analyzer house.
- Air conditioning may be necessary if ambient temperature and/or humidity are high. The system shall be capable of controlling relative humidity to prevent condensation.
- Conditions inside the house shall be within the analyzer manufacturers' recommended ratings.

4.1. Air Change Rate

The ASV is to design the air handling system to meet the following requirements. The system shall be capable of ventilating the house at a rate sufficient to dilute any leakage to less than 25 percent of the lower flammable limit based on the largest single failure.

4.1.1. Air Conditioning

- Air conditioning units shall be mounted outside the shelter and designed for the Mobil-specified electrical area classification and local weather conditions.
- Air conditioning coils shall be resistant to H_2S in the atmosphere.
- Alarm contacts shall be provided and shall open to indicate failure of air conditioning and also to indicate fresh air flow below design rate. Alarm shall be local.

4.1.2. Forced Ventilation

Air for forced ventilation preferably shall be taken from a safe location. In a Division 2 classified area, the air intake shall be at least 7.6 m (25 ft) from any gas source. Provisions shall be made for rain shields and wire-mesh protection. A removable dust filter shall be provided.

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4.1.3. Louvers

Air shall be released by weighted barometric louvers located at the tops and bottoms of the house walls. The louvers shall be designed to maintain back pressure of 5 mm (0.2 in) water gauge within the shelter.

- At least half the louvers shall be operative under any local wind condition. Each vent shall be protected to prevent accidental damage.
- They shall also be protected by screens against the entry of insects and vermin and by other means against the accumulation or ingress of blocking debris such as leaves, sand or snow.

4.1.4. Fans

The design of the ventilation or air conditioning system and the mounting position of the fans shall ensure that there is an even distribution of air within the shelter, thus avoiding local accumulation of hydrocarbons.

- All fans shall be of nonsparking, explosion-proof construction.
- Fan noise shall be less than 70 decibels.
- Fan and motor bearings shall be designed for a minimum life of three years.

4.2. Alarms

An alarm or alarms shall be provided in accordance with IEC 1285, Paragraph 5.6.2.

NOTE: When the hazardous material is lighter than air, the detector shall be at or near roof level. When the hazardous material is heavier than air, the detector shall be at or near floor level. Both high and low detectors may be required. Sufficient clearance shall be provided for calibration.

Safety alarms from the surrounding plant shall be detectable inside the shelter. Consideration shall be given to the installation of a telephone link to a permanently manned location.

5. Electrical Requirements

Depending on the probability of a flammable mixture and hence the source, reliability and redundancy of the ventilation, the house interior may be classified in accordance with NFPA 497A or other local relevant standard as Class 1, Division 2 or General Purpose.

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5.1. Associated Equipment

Electrical equipment shall include all that is necessary for the operation of the analyzer house and the associated equipment. This equipment shall include distribution panels and facilities for incoming power wiring. The power supply shall be wired through the common junction box mounted on the outside of the shelter for field connection.

5.2. Wiring

Wiring between terminals shall be continuous runs and shall not be spliced. With the exception of solid jumpers, not more than two wires are to be connected to one terminal.

5.3. Wire Segregation

The following classes of wiring shall be segregated:

- AC wiring
- Intrinsically safe DC signal wiring
- Non-intrinsically safe DC signal wiring

5.4. Power Distribution Panels

The ASV shall supply, install and wire power distribution panels for all equipment provided in the house.

- Each of the main systems shall have an individual isolation circuit breaker for air conditioning systems, lighting systems, receptacles, instrument power supply and each instrument.
- All circuit breakers shall be properly identified and labeled with permanent markings.
- 15 percent or two spare breakers shall be provided for future expansion.

5.5. Receptacles

Electrical receptacles shall be provided on each 2 m (6.5 ft) of wall length for the purpose of connecting test equipment. Receptacles shall meet the electrical classification requirements of the house interior.

5.6. Lighting

- Overhead fluorescent or incandescent lighting with switches is required.

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- Lamp wattage and quantity shall be sufficient to provide a minimum of 830 lux (77 foot-candles) of illumination initially and 540 lx (50 fc) in service at an elevation of 750 mm (30 in) or at work level.
- Lighting and switches shall comply with the electrical classification of the house interior. A light switch shall be provided at the inside of each door.
- Lights shall be provided above any external sample conditioning system.

5.7. Cable Tray and Conduit

Cable tray is acceptable inside the house. All conduit connections shall be rigid galvanized and at least 12.5 mm ($^1/_2$ in) threaded. All necessary explosion-proof seals shall be provided, but the seals shall not be poured until after completion of all acceptance testing.

5.8. Ground Wire Sizing

A No. 2 AWG (6 mm diameter) or greater ground bus shall be mounted on and connected to the base frame. It shall be used for all safety grounding to be supplied as part of the house and connected to case grounds. Cases shall not rely on grounding through the steel of the house. Separate low-resistance grounds are required for signals and intrinsic safety.

5.9. Termination Cabinets

- Separate terminal cabinets outside the house for AC, analog DC and digital DC shall be NEMA 4X stainless steel or aluminum wall-mounted enclosures, fully gasketed, continuous hinge, with captive door clamps.
- The cabinets shall accept all external field connections to the analyzers.
- All wires shall be number tagged at each end by means of a small plastic sleeve permanently stamped as shown on the wiring diagram.
- Each terminal block shall have a minimum of 25 percent spares.

5.10. Main Power

- Main power to the house and its contents shall be a 220/208/110 V 4-wire supply or 480 V 3-wire supply with transformer depending on the house electrical load.
- A single breaker shall be installed on the outside wall to disconnect all main power to the house. This breaker shall be tagged with the location of the power source.
- Power to individual consumers such as analyzers, lighting, ventilation fans and air conditioning shall be distributed via breakers inside the house.
- The ASV shall provide calculations to demonstrate that phase loads are balanced.

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- Where the interior of a house is intended to be made general purpose by virtue of secure ventilation, one fan and all the house contents shall be powered from one substation and the second fan shall be powered from a different substation.

6. Piping and Tubing Requirements

6.1. Piping and Tubing

All piping and tubing from headers and analyzers inside the house shall be brought to the outside of the shelter so that, at the job site, all connections can be made outside the shelters. The piping and tubing extending outside the shelters shall be in the horizontal direction and shall be firmly secured by support racks attached to the house.

6.1.1. Nameplates

All inlet piping, tubing and bulkhead connections shall be labeled with permanent nameplates both inside and outside the house. Nameplates shall be 16 U.S. gauge (0.0598 in thick) stainless steel with lettering at least 12.5 mm ($^1/_2$ in) high.

6.1.2. Tubing and Piping Location

Tubing and piping runs shall not interfere with maintenance of any analyzer nor encroach on space allotted for future instruments. All valves and instrument items shall be easily accessible. All tubing and piping shall be tested for absence of leaks

6.1.3. Utility Piping and Interconnecting Tubing

1. A minimum NPS $^3/_4$ header shall be provided for each utility (steam, air, cooling water, etc.) with a shutoff valve outside the shelter or cubicle.
2. Headers shall terminate with valve and plug to permit later extension to other users.
3. One additional accessible valved and plugged outlet shall be provided on each header inside the shelter or cubicle to facilitate temporary connections.
4. Headers generally shall be carbon steel, except the instrument air header, which shall be galvanized. Polymers or low-melting-point metals or alloys shall not be used on lines carrying toxic or flammable fluids.
5. Each user shall have an individual shutoff valve.
6. Lines where condensation can occur (steam, air, vent) shall slope to a low point.

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7. Aromatic-solvent-resistant sheathing is required for copper tubing used on cold service.
8. All connections or bulkheads on lines at temperatures other than ambient shall be thermally isolated from the shelter structure.
9. Tubing connected to vibrating equipment (e.g., pumps) shall include provisions for vibration dampening.
10. Tubing connected to cylinders shall include a pigtail to allow convenient replacement of cylinders.
11. Tubing runs shall be organized and installed in logical groups and in a manner that allows convenient identification.
12. All piping and tubing shall be adequately supported. (All tubing shall be protected by running it in trays or channels.)

6.1.4. Air

Failure of a single filter/pressure reducer (air set) shall result in the failure of not more than one analyzer.

6.1.5. Cooling Water

The cooling water supply header shall have dual strainers and drain valves to permit filter replacement without analyzer shutdown.

6.1.6. Atmospheric Vent Header

The external stack (removable for shipment) shall be designed to minimize the effect of wind and rain on the analyzers.

6.2. Steam Traps

- Traps shall be provided outside the house for all steam-traced inlet sample lines as well as all steam users. Each steam user shall have its own trap.
- For personnel safety and climate control, as much of the steam piping and tubing as possible shall be located outside the shelter.
- The supply header shall have a strainer with blowdown valve and a steam trap.
- Any condensate return header shall have an outlet check valve. Each parallel user shall have an individual steam trap. All steam lines shall be insulated for personnel protection and to prevent heat loss.

6.3. Hazardous Materials

- Hazardous materials shall not be stored inside the house.

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  - Systems handling hazardous materials shall be located, to the maximum extent practical, outside the house.
  - A valve to shut off each line entering the house shall be outside the house and readily accessible from grade, platform or permanent ladder.
- Normal sources of release such as vents, vented regulators, relief valves, check sample taps and calibration sample containers shall be outside the house.
- Flow of hazardous materials entering the house shall be limited by a device located outside the house. The device shall limit the flow so that, even with a broken connection inside the house, the maximum flow of hazardous material combined with the normal ventilation flowrate cannot produce a concentration higher than 25 percent of the lower flammable limit.
  - An excess-flow valve is the preferred flow restriction device.
  - The device may also be a flow restriction orifice, capillary or locked flow controller.

6.4. Materials

Type 316 seamless stainless steel tubing shall be standard. Other materials (Monel, for example) may be considered where required by process conditions. Any deviation shall be offered to Mobil for approval. The minimum wall thickness shall be as shown below:

O.D. (in)	Thickness (in)
$^1/_8$	.028
$^1/_4$	.028
$^3/_8$	.035
$^1/_2$	.035

6.5. Other Requirements

No asbestos or material recognized as being hazardous shall be used.

7. Cylinder Rack Requirements

- Stable, freestanding fixed groups of cylinders (such as four-packs) do not require racks.
- All structural steel for racks shall be welded and hot-dip galvanized.
- Cylinder racks shall have mounting plates with holes for field installation on a concrete pad with anchor bolts.

- Cylinder storage racks shall have a chain or bar for each cylinder with means to hold the cylinder in place and prevent tipping. Cylinders shall be stored outside the analyzer house and not closer than 3 m (10 ft) to potential fire sources such as pumps or other hazardous process equipment.
- A blast-resistant barrier or spacing requirements may be necessary if cylinders of oxygen or air under pressure are present in the same rack as cylinders of combustible hydrocarbons.
- At least two cylinders for each header shall be equipped with automatic switchover. Manifolds shall be piped and mounted on the proper racks on the outside wall of the analyzer house.

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Appendix E: Package Subcontract

1. General

- The analyzer systems shall consist of process analytical instruments with sample systems and related equipment completely assembled in packages, tested and ready for installation at the job site.
- The analyzers, sample systems and related equipment shall be mounted and interconnected with all utilities and accessories to provide fully contained and operational systems within the packages.
- Termination of all connections to the analyzer systems shall be external to the packages, so that no access shall be required to the interior of analyzer systems to facilitate the installation of the packages in the field.

2. Work by Others

Piping and wiring to and from the analyzer houses shall be provided by others.

3. Seller's Responsibilities

The analyzer systems supplier shall be responsible for all activities required to manufacture and run the analyzer systems. The supplier shall provide design, engineering, procurement, manufacturing, installation and testing services as required to acquire all equipment and materials to fabricate, assemble, test, install and precommission the analyzer systems.

The extent of work shall include, but not be limited to, all of the following:

1. Complete sample system design, which shall conform to API RP 550, Part II and IEC 1831/TR.
2. Review of analyzer vendor's sampling system for suitability and economy.
3. Procurement of all process analytical instruments including accessories and documentation according to specifications.
4. Procurement of all analyzer systems and sample conditioning systems components according to specifications.

5. Specification and procurement of all bulk materials and equipment required for fabrication and assembly.
6. Design and supply of sample takeoff probes.
7. Design and supply of sample recovery systems.
8. Supply or procure all the application engineering required to attain the specified analyses
9. Supply or procure all the software needed to operate, maintain and troubleshoot the equipment
10. Define power requirements, floor loading, floor area requirements, package shipping dimensions and heat and noise generation calculations for the entire system and its peripherals.
11. Coordination and expediting of all purchase orders.
12. Fabrication and assembly of all analyzer systems and subassemblies.
13. Design and construction of analyzer validation system.
14. Quality assurance of all work.
15. Provide guarantees on all equipment including analyzers and systems.
16. Complete system checkout and calibration before shipment from system supplier to plant site.
17. Testing and preparation for customer inspection of all analyzer systems.
18. Complete system documentation including drawings, operation and maintenance manual and parts list. The manual shall include a troubleshooting procedure and fault analysis.
19. Preparation and submittal of analyzer system documentation and data.
20. Total system training at system supplier facility and plant site.
21. Final commissioning of the analyzer following plant commissioning and the correction of all faults in the analyzer system prior to its acceptance by Mobil.
22. Program documentation of a microprocessor-based analyzer and inclusion of necessary programming instructions.
23. Preparation and submittal of recommended analyzer systems spare parts.
24. Preparation of all analyzer systems for shipment.
25. Loading and shipping of all analyzer systems to the job site.
26. Provide onsite supervision of installation.
27. Provide calibration, checkout, operator training and startup assistance.
28. Provide instruction on operation and maintenance of analyzers and systems for onsite personnel.
29. Provide owner with an acceptable maintenance contract for local support of the system after expiration of the warranty period.

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30. Identify future source of consumables and assist buyer in arranging permanent source of supplies. Provide sufficient consumables for field startup and calibration and for first two weeks of operation.

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Inst. Inspection, Testing, Calibration, Pre-Commissioning

MP 32-P-13

March 1998

Scope

This Mobil Engineering Practice (MEP) covers the best practices for the acceptance of instrumentation prior to commissioning. It discusses the procedures, basic standards and facilities required for inspection, testing, recalibration and loop testing. Most instrumentation shall be inspected and tested prior to site delivery. Should this not be the case, more extensive calibration and testing may be necessary in the field. The specific procedures for testing complex analyzers, fire and gas, distributed control and emergency shutdown systems, except as part of loop testing, are outside the scope of this Practice.

Table of Contents

Scope **1**

1. References **5**

1.1. MEPS–Mobil Engineering Practices 5

1.2. API–American Petroleum Institute 5

1.3. Energy Industries Council-Contractors Committee on Instrumentation 5

1.4. ISA–Instrument Society of America 5

2. General Testing **6**

2.1. Site Shop Testing 7

2.2. Post Installation Control Panel Testing 7

2.3. Post Installation Field Tests 7

3. Facilities for Test and Calibration **8**

4. Equipment for Test and Calibration **9**

4.1. Pressure Source 9

4.2. Pressure Measurement Testing 9

4.3. Temperature Source Testing 10

4.4. Thermocouple/RTD Simulation/Measurement 10

4.5. Other Electronic Test and Calibration Equipment 10

4.6. Instrument Shop Test Setup With Calibration PC 11

5. General Procedures for Testing **11**

5.1. Safety 12

5.2. Recalibration 12

6. Calibration Check Tests **12**

6.1. Leak Test (Pneumatic Instruments) 13

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6.2. Transmitter Calibration Test 13
6.3. Controllers (Non-PES) 13
6.4. Direct Process Connected Controllers 14
6.5. Pressure Switches 14
6.6. Temperature Switches 14
6.7. Level Switches 15
6.8. Flow Elements 15
6.9. Solenoid Valves 15
6.10. Current to Pneumatic Converters 15
6.11. Control Valves 16
6.12. Safety Relief Valves 16
6.13. Chart Recorders 17
6.14. Integrators (Counters) 17
7. Power and Air Supply Tests 18
7.1. AC Power 18
7.2. DC Power Supplies 18
7.3. Instrument Air 18
8. Field Inspection/Mechanical Acceptance 19
8.1. Pressure Testing 19
8.2. Cable Testing 19
9. Protection During Line Flushing and Hydrostatic Pressure Testing 20
10. Loop Testing 21
10.1. General 21
10.2. Input Simulation 22
10.3. Programmable Electronic Systems (PES) 22

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10.4. Hazardous Zones..... 23

10.5. Test Procedures..... 23

11. Test Administration and Documentation..... 24

11.1. Inspection, Calibration and Loop Test Records 24

11.2. Loop Acceptance 25

11.3. Forms..... 25

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1. References

The following publications form a part of this Practice. Unless otherwise specified herein, use the latest edition.

1.1. MEPS–Mobil Engineering Practices

MP 32-P-01	General Requirements for Instrumentation
MP 32-P-04	Control Valves and Actuators
MP 33-P-16	Electrical - AC Uninterruptible Power Supply (UPS) System

1.2. API–American Petroleum Institute

API STD 527	Seat Tightness of Pressure Relief Valves Third Edition (R 1996)
API RP 576	Inspection of Pressure- Relieving Devices First Edition

1.3. Energy Industries Council-Contractors Committee on Instrumentation

CCI P/1	Instrument Installation Testing Procedure

1.4. ISA–Instrument Society of America

ISA RP7.1	Pneumatic Control Circuit Pressure Test; (Approved July 1, 1956) Superseded by: S7.0.01: 1996
ISA RP12.6	Wiring Practices for Hazardous (Classified) Locations Instrumentation Part 1: Intrinsic Safety

2. General Testing

The procedures, basic standards and facilities required for inspection, testing, recalibration and loop testing of instrumentation shall be in accordance with requirements of this MEP, unless superceded by more stringent local regulations.

To achieve a smooth plant startup, the contractor shall test all instrumentation for general operability and calibration in accordance with project specifications and to the satisfaction of the Mobil inspector.

1. All instruments shall be factory calibrated to the required range.
2. Recalibration at the site shall only be performed if the instrument fails a calibration test.
3. Instrument testing shall take place in the following sequence:
   a) Factory Acceptance Test
   b) Site Calibration Test / Recalibration (shop or field)
   c) Post Installation Mechanical Inspection (piping, tubing, etc. after line flushing)
   d) Cabling and Wiring Check
   e) Loop Testing
4. The location of testing is constrained by the size and type of instrumentation and is summarized in the following table.

Table 1: Recommended Testing

	Factory Acceptance Test	**Site Shop Calibration Check**	**Field Installed Calibration Check**	**Post Install Mechanical Inspection**	**Wiring Check Loop Testing**
Local Indicators, Gauges	NR	NR	NR	R	NR
Transmitters, Transducers, Local Controllers	NR	R	NR	R	R
Switches, Level Displacers, Solenoids, I/P Converters, Counters Chart Recorders	NR	NR	NR	R	R
Analyzers, Control Valves, Safety Relief Valves, Instruments on Pre-Assemblies and Control Panels	R	NR	R	R	R

R=Recommended NR=Not Recommended

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2.1. Site Shop Testing

Instruments functionally tested and/or calibrated in field test shops are as follows:

- Transmitters
- Indicating, recording and blind controllers

All panel, console and control center instrumentation not covered by tests on the panel are described in the next paragraph.

2.2. Post Installation Control Panel Testing

When instruments are shipped to the field already mounted on a piped and/or wired panel (local or control room), they shall be tested on the panel, unless the manufacturer instructions call for their removal and bench testing or bench testing is more convenient. Such instruments include, but are not limited to, the following:

- Panel-mounted discrete modules including: control stations, controllers, recorders, indicators, integrators, ratio/biasing/computing relays, thermocouple and millivolt amplifiers.
- All other panel-mounted instrumentation such as alarm switches, solenoid valves, auxiliary relays, alarm lights, annunciators and audible devices.

2.3. Post Installation Field Tests

All instruments shall undergo a post-installation mechanical inspection. Instruments functionally tested and/or recalibrated in the field are as follows:

- Simple analyzers such as pH, conductivity, oxygen, etc.
- Instruments that are part of pre-assembled modules or skid units.
- Instruments too bulky or heavy to be conveniently moved to the test shop. Such instruments include, but are not limited to:
  - Control valves
  - External displacement transmitters/controllers
  - Heavy-duty ball float transmitters/controllers
  - Tank level gauges
  - Nuclear level and position devices
  - Meter provers

If recalibration is required, all instruments shall be calibrated according to vendor instructions, where available. As a minimum, the applicable tests outlined in the following sections shall be carried out.

3. Facilities for Test and Calibration

A suitable, onsite instrument workshop, adequately equipped for instrument calibration, shall be provided.

- The workshop shall have adequate storage for calibrated instruments.
- The workshop shall be separate from other construction or testing areas.
- On large, dispersed installations, an equipped mobile work truck shall be considered.
- Depending on the type and magnitude of the project, the workshop shall have the following facilities:
  - A source of clean, dry, oil-free instrument air.
  - Main electrical supplies having frequency and stability characteristics equal to the permanent supply.
  - Transformers, as required.
  - Instrument power supplies: Where the equipment of the final system cannot be used, the contractor shall provide a direct current (DC) supply of the required voltage and characteristics.
  - Portable radio transmitter/receiver sets for loop testing: Sets shall be certified intrinsically safe if they are to be used during plant startup, shall have a suitable power level (not too high or low) and shall not conflict with the plant radio system.
  - Air filtration system and, in some locations, air conditioning to maintain a dust-free environment.
  - The onsite workshop shall incorporate clean, dry and secure storage for instrumentation awaiting test or installation after test.
  - Basic cleaning facilities.
  - Miscellaneous tools, fittings and consumable materials.
  - Lifting and handling gear.
  - Personal computer(s) with adequate disk and memory to execute instrument index, database and calibration test software.

4. Equipment for Test and Calibration

Test equipment shall be equal, in all respects, to the instrument vendor recommendations as stated in calibration and maintenance instructions. This equipment shall include any special tools or jigs that are standard supply from the particular instrument vendor. Mobil approval is required for all equipment provided. Quantities shall vary according to the size of the project.

Calibration equipment shall preferably be 10 times (but at least four times) more accurate than the specified accuracy of the instrument (e.g., if an instrument's accuracy is ±0.25 percent, the calibrator shall be ±0.05 percent). All calibration equipment shall be certified so that it is traceable to the appropriate standards body (e.g., NIST). Equipment is to be calibrated in the engineering units selected for the project.

Test and calibration equipment shall include, but not be limited to, those items listed in the following paragraphs. Equipment is required to simulate process conditions and read the instrument. Combinations of equipment may be obtained as calibration kits.

4.1. Pressure Source

The following table describes four generally available types of pressure sources.

Table 2: Pressure Sources

Pressure Range	Pressure Source/Area of Use
<7 bar (100 psi)	For shop use, air compressor (either portable or from plant supply) and air filter regulator sets
<35 bar (500 psi) and Vacuum	For field and shop, portable air hand pump (Transcat model Q5863P or equivalent)
>35 bar-shop use	Hydraulic deadweight tester and gauge comparator
>35 bar-field use	Hydraulic hand pump

4.2. Pressure Measurement Testing

Required equipment includes, but is not limited to:

- At least two Intelligent Pressure/Electrical Calibrators with temperature compensation, at least 0.05 percent span accuracy and selectable engineering units. The calibrator shall also support programmable automated test procedures and a

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personal computer interface. (Fluke Model 702 with pressure module 700P08 or equivalent).

- At least two variable range digital pressure indicators with 0.1 percent span accuracy.

4.3. Temperature Source Testing

Required equipment includes but is not limited to:

- Thermostatically controlled temperature bath(s). Typically only used to test filled systems.
- Thermostatically controlled oven for checking thermocouple reference junction compensation.

4.4. Thermocouple/RTD Simulation/Measurement

Required equipment includes but is not limited to:

- At least two Intelligent Temperature/Electrical Calibrator/Simulators with programmable automated test procedures, selectable engineering units and personal computer interface. (Fluke Model 702 or equivalent).
- Test leads complete with test probes and clips and distribution terminals. Thermocouple compensating wire for use in calibration of thermocouple instruments.
- Millivolt/temperature conversion charts.
- RTD temperature conversion charts.

4.5. Other Electronic Test and Calibration Equipment

Other test equipment shall include but is not limited to:

- At least two portable digital multimeters with an accuracy of ± 0.05 percent of range or better, a discrimination of 10 microvolts or better and incorporating an internal calibration/standardizing feature and 0.1 percent calibration resistors. Resistance of 20,000 ohms per volt on DC range.
- For use with smart transmitters, at least two portable calibrators to support field calibration of these devices.
- At least two portable digital precision (± 0.05 percent) millivolt, volt and milliamp source devices.
- Two 250V insulation resistance testers.
- One electronic stopwatch and one relay contact timing device.
- A portable battery powered oscilloscope with LCD display.

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- Pulse counter/timer.
- Pulse/frequency generator.
- Meters to measure capacitance, inductance or L/R of intrinsically safe cables.

4.6. Instrument Shop Test Setup With Calibration PC

Traditional instrument calibration procedures and records have been done using paper forms and records. However, the availability of intelligent calibrators and personal computer (PC) software has enabled the automation of many test procedures and allowed direct capture of test results. The use of a PC with appropriate software (refer to Section 11) is recommended for larger projects. An interface between the calibration PC and a plant instrument index database is also possible. The following figure shows a typical instrument calibration setup using a PC.

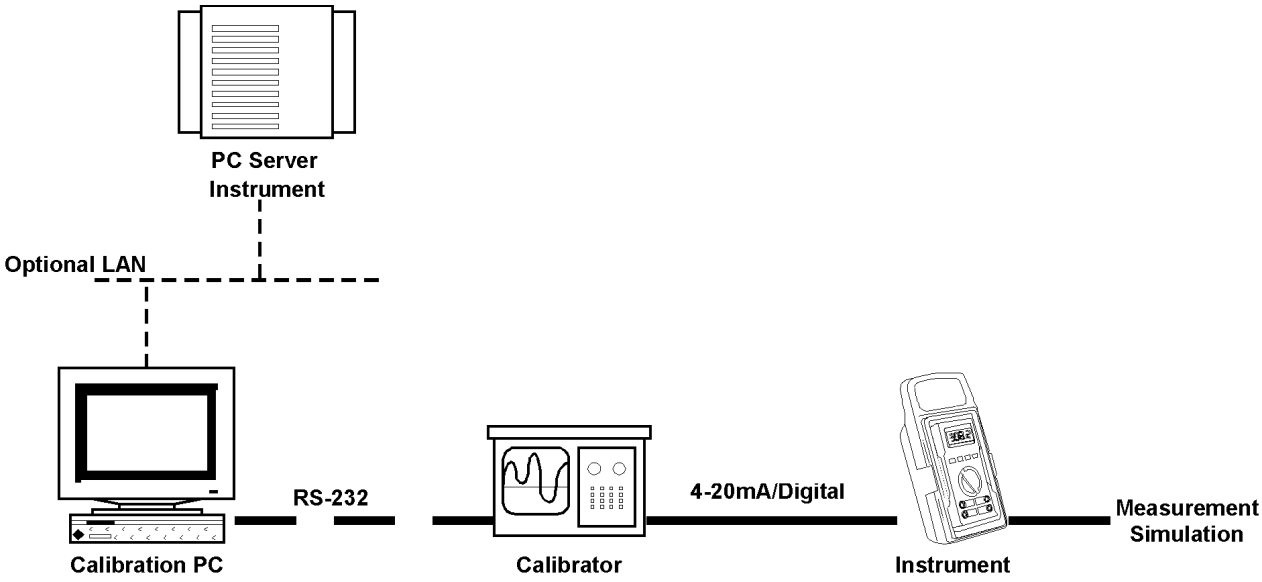

Figure 1: Instrument Calibration Setup using a Personal Computer

5. General Procedures for Testing

Prior to functional testing, each instrument data plate shall be checked against the latest version of the data sheet to confirm model number, operation, action, certification, etc. and be inspected to ensure against damaged or incorrect parts. Each instrument is supplied with a nameplate indicating tag name and service as per MP 32-P-01.

The contractor shall ensure that copies of all manufacturer installation and calibration instructions are available in the field prior to the commencement of work. It is the contractor's responsibility to

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ensure that the installation, calibration and checkout of the instruments meet the requirements of this Practice and project specifications.

Where the contractor does not have the skills required to test or calibrate specialty items such as complex analyzers, multiplexer systems or blenders, the contractor is required to obtain the assistance of an outside source (with Mobil approval), such as the equipment manufacturer.

5.1. Safety

Any air system, permanent or temporary, used for energizing instrumentation shall be dry and clean at all times and shall be blown down thoroughly before use. An excessive air supply pressure shall be avoided. Any connection between the air supply system and an instrument under test shall be via an adequate filter and regulator.

Plastic sealing plugs shall be kept firmly fixed in all pneumatic instrument connections, except during test and immediately before final plant connection.

Care shall be observed when connecting electrical power supplies to electrical and electronic instrumentation.

- Ensure correct voltage and frequency on alternating current (AC) supplies.
- Where DC is used, check that the voltage regulation and any superimposed ripple are within the instrument manufacturer specification.
- Correct polarity of supply and proper grounding are critical to transistorized equipment.

5.2. Recalibration

All instruments are factory calibrated and shall be delivered with appropriate calibration certificates. Recalibration shall only be carried out if the calibration check test (when required) reveals recalibration is necessary. Should recalibration not be possible within a reasonable time, the instrument manufacturer shall be consulted regarding replacement or repair.

6. Calibration Check Tests

All instruments shall be calibrated by the manufacturer before delivery to the plant site. To validate this calibration, the applicable tests described below shall be carried out. These tests may be applied in an instrument shop, on control panels or in the field. The recommended testing and test locations are indicated in Table 1. Procedures are based on CCI P/1.

6.1. Leak Test (Pneumatic Instruments)

Apply maximum signal input pressure to the process connection, close the inlet valve and disconnect the pressure source. Observe the pressure measurement on the signal inlet, and ensure there is no fall-off in pressure over a three-minute period.

6.2. Transmitter Calibration Test

If a PC or documenting calibrator is used, the appropriate calibration test procedure shall be set up. The instrument shall be connected to the test set-up. For differential pressure cells, the pressure is applied to the high-pressure side, leaving the low-pressure side open to atmosphere.

- For smart transmitters, upload the instrument data to a hand-held communicator or the calibration PC and confirm the range and other settings are correct.
- Raise and lower the input signal and record the corresponding output at approximately 0, 25, 75, and 100 percent on a rising signal, and then 75, 25 and 0 percent on a falling signal of the instrument range. The exact 0, 25 percent, etc. values do not have to be set as actual values, they can be entered into the calibration program. It is important, however, to move in one direction only so that any instrument hysteresis is canceled out.
- The software shall calculate the percentage error, and this value shall not exceed manufacturer specification.
- If the percentage error does not meet specifications, a recalibration shall be performed according to manufacturer specifications. If the instrument fails again, following recalibration, the instrument manufacturer shall be consulted regarding replacement or repair.
- For thermocouple-based temperature transmitters, the accuracy of reference junction compensation is checked by testing the immunity of the temperature reading to ambient temperature changes. The instrument shall be checked using a thermostatically-controlled oven to change the temperature of the reference junction (normally incorporated into the transmitter) while measuring a constant temperature.

6.3. Controllers (Non-PES)

When preparing to check a controller, either connect the output of the pneumatic controller to the input via a 3 m (10 ft) length of 6.350 mm ($^1/_4$ in) OD tubing and a capacity pot of 980 cm^3 (60 in^3) volume, or connect the output of an electronic controller to the input through a resistance equivalent to the average load resistance and a parallel connected 1 µF capacitor.

1. Place controller action reverse acting, proportional band 100, integral and derivative times for minimum effect.

2. Set to auto, adjust set point to 50 percent of scale, and verify controller output is 50 percent.
3. Move set point up and down scale, and verify that the output follows the set-point.
4. Set to manual, and verify output can be moved for 0–100 percent.
5. Return controller to specified installation settings.

6.4. Direct Process Connected Controllers

A suitable means is required to simulate the controlled process variable.

1. Place controller action direct acting, proportional band 100, integral and derivative times minimum.
2. Set to auto, adjust set point to 50 percent of scale with measurement at 0 percent.
3. Increase process variable to above 50 percent, at which controller output shall change for minimum to maximum.
4. Set process variable to 50 percent, and verify output settles at 50 percent.
5. Set to manual, and verify output can be moved for 0–100 percent.
6. Return controller to specified installation settings.

6.5. Pressure Switches

Connect pressure switch to pressure source and pressure calibrator. Connect switch contacts to continuity meter.

1. Increase and then decrease pressure, and note switch activation and reset pressures.
2. Verify switch contacts activate within specified accuracy of set point.
3. Verify switch contacts reset within specified deadband.

6.6. Temperature Switches

Immerse temperature sensor in temperature bath.

1. Connect switch contacts to continuity meter.
2. Increase and decrease bath temperature, and note switch activation and reset temperatures.
3. Verify switch contacts activate within specified accuracy of set point.
4. Verify switch contacts reset within specified deadband.

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6.7. Level Switches

Field installed level switches shall be checked by partial immersion of the displacer or float, with water in the float or displacer chamber or stilling tube.

- Due recognition shall be given to the difference in gravity between water and the application fluid(s).
- The water shall be fully drained from the system after testing.
- The trip point shall be at the defined point (normally the center of the float chamber).
- Observe control console (or use continuity meter) to read switch state.
- Verify contact action by changing water level for both rising and falling levels.

6.8. Flow Elements

Flow elements (i.e., orifice plates, turbines, venturi nozzles) shall not be installed until line flushing has been completed. Orifice plates shall be checked visually for the following:

- Smooth, perfectly flat surfaces without scratching or bowling
- A sharp, non-reflecting edge on the upstream face where relevant, or a radius on a quadrant-edge orifice
- The correct bore as measured by internal micrometer or calipers
- Correctly stamped identification and bore dimensions on upstream face of tag handle

It is normally not practical to validate the dimensions of other differential pressure (DP) producers, such as venturi nozzles, all tubes and inserts under site conditions.

6.9. Solenoid Valves

Connect air supply to appropriate port(s) and appropriate power supply via a switch. Switch solenoid, and verify operation of valve.

6.10. Current to Pneumatic Converters

The input terminals shall be connected to an adjustable precision current source, which is measured to ± 0.05 percent, and the output air signal calibrated to its nominal range, normally 0.2–1.0 bar (3–15 psi).

Check the linearity, hysteresis and dead band, etc. at 0, 25, 75 and 100 percent—which shall be within the manufacturer's quoted specifications.

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6.11. Control Valves

Control valves shall be inspected and tested at the manufacturer's factory. MP 32-P-04 gives a detailed checklist for the items and features that shall be checked out before acceptance. A Mobil representative shall witness these tests at the factory or as a field demonstration.

Calibration shall be checked, after installation in the field, before flushing, using the following procedure. Valves shall be re-stroked after flushing as part of loop testing.

1. Note the operating range of the diaphragm actuator from data plate or specification.
2. Connect a suitable regulated air supply with pressure calibrator to the diaphragm case connection bypassing valve positioner if present.
3. Increase the air pressure, and check the valve spindle position from the valve stem position indicator. The travel shall be checked at 0, 25, 75 and 100 percent of input pressure on increasing and decreasing pressure.
4. Verify position is within the manufacturer-specified tolerance. If not, recalibrate the valve actuator according to manufacturer procedures.
5. Additionally for valves with positioners, connect air to the positioner's air supply connection and connect 4-20 mA current source or variable air source to the positioner input signal connection.
6. Adjust input signal to 0, 25, 75 and 100 percent, and verify valve position is within manufacturer tolerance. If not, recalibrate the valve positioner according to manufacturer procedures.
7. Disconnect first the input signal and then the air supply. Verify valve fails to correct position.

6.12. Safety Relief Valves

Safety relief valve testing is sometimes outside of the scope of the instrument contractor, and the following is a general guide only. Standards API STD 527 and API STD 576 or other appropriate national standards are applicable to these tests. Safety relief valves are normally tested in a workshop with a suitable manufacturer-specified test rig. Testing shall include "Popping and Reseating" and "Seat Leakage" tests.

6.12.1. Popping and Reseating Test

1. Mount valve in test rig, and connect pressure source (usually air) and appropriate pressure indicator with maximum indicator.
2. Slowly increase pressure until the valve pops, and note maximum pressure.
3. Slowly decrease pressure until the valve reseats, and note pressure.

4. If pressures are not within the specified tolerance, adjust valve according to manufacturers instructions.

6.12.2. Seat Leakage Test

1. Increase pressure to pop the valve, then lower and hold at 10 percent below set pressure.
2. Refit outlet flange with safety plug and immerse open end of the bleed pipe in water.
3. Note the leakage rate by observing bubbles appearing per minute.
4. If rate exceeds permitted tolerance, adjust valve according to manufacturer instructions.

6.13. Chart Recorders

Perform the following checks to test the operation of chart recorders:

1. Check motor for correct frequency.
2. Check pneumatic and electric chart drives for noise-free operation and steady chart drive take-up.
3. Check pen stability when recorder is partially withdrawn from case.

6.14. Integrators (Counters)

Integrators shall be tested with a consistent signal (normally 4-20 mA current source), and the value shall be checked for consistency, at least at the start and finish of each calibration period. Tests are made by calculating a time period for a given input signal to accumulate a fixed number of counts and then recording actual counts for that time period and input signal.

- The duration of test count period shall be calculated to ensure that at least ten times the accumulated number of counts can discriminate one-tenth part of the vendor's quoted accuracy.
- The tests shall be made at:
  - Zero signal
  - Lowest signal value (cutoff value)
  - 50 percent of signal input
  - 100 percent of signal input
- The total counts registered in each test shall be considered against the elapsed time and the factor of the integrator.

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7. Power and Air Supply Tests

Power supply tests and procedures shall be planned and agreed upon by Mobil, the contractor and the vendor. In the absence of such a procedure, the tests cited in the following paragraphs shall be carried out.

7.1. AC Power

Each isolator/fuse shall be opened or removed to ascertain that it is unique to that load and no other.

- The switching time for automatic transfer of supplies or feeder lines at full load shall be checked and measured by a relay contactor timing device or oscilloscope. (See MP 33-P-16 Electrical–AC UPS System).
- Where AC power to instrumentation is derived from a three-phase supply, the actual load on each phase shall be measured and any out-of-balance load corrected.
- The fuse coordination shall be checked. This is especially important on critical shutdown and control systems.

7.2. DC Power Supplies

Check the power supply fault protection and reset mechanisms, as supplied against the vendor-specified rating.

- The reset mechanism may be of a type with a built-in protection trip, which disconnects before the load fuse blows, or one that can sustain an overload for sufficient time for the DC load fuse to fail.
- The DC load fuse shall always fail before the AC protection.
- Check the system supplied for power transfer under load from power supply to battery for the loss of AC supply, and power supply to alternate/standby power pack of batteries for a power pack failure.
- The voltage at the load terminals shall be monitored during the above tests.
- If power supply has amp meters, check the inrush current at switch-on under load.

7.3. Instrument Air

Check that the designated air supply valve to a particular instrument is unique to that instrument and no other.

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8. Field Inspection/Mechanical Acceptance

Field inspection and testing of instrument process piping, pneumatic systems, electrical connections, instrument cabling, grounding and shielding systems is necessary for all instruments irrespective of where they may have been calibrated or tested originally. Inspection shall take place before final loop tests are performed. The inspection and testing procedures are based on standard CCI P/1.

The mounting shall be considered mechanically complete when:

- The instrument is installed in accordance with the process, purge and pneumatic piping, and the electrical conduit and wiring designs.
- The instruments, piping and wiring are securely supported.
- The identification tags are present, containing the required information.
- The location is accessible by the agreed upon design method. Access does not require climbing over, under or through equipment.
- The steam tracing and condensate disposal (or electrical tracing), where required, are installed and operable.
- When intrinsic safety barriers are used, the installation is in accordance with ISA RP12.6.

8.1. Pressure Testing

Air supply piping, transmission/signal tubing and process impulse piping shall be blown through with clean oil-free dry air and checked for leaks.

- Tubing pressure testing (per ISA RP7.1) has to be done prior to steam tracing and insulation.
- A soap solution test can be used for locating leaks.

8.2. Cable Testing

After cables are laid and before connection, all thermocouple, electric and electronic instrument wiring shall be checked for polarity continuity and insulation resistance before final loop testing.

- No insulation resistance testing (meggering) shall be carried out after cables are connected to instruments.
- Underground cables shall be tested before back filling.

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- Coaxial and optical fiber cables used for data highways and networks shall be tested with appropriate test equipment to validate continuity and that signal attenuation specifications are not exceeded.

9. Protection During Line Flushing and Hydrostatic Pressure Testing

During flushing and hydrostatic testing of piping, the following instrument protection procedures shall be adopted:

1. Have contractor prepare an adequate number of spool pieces for temporary replacement of control valves, turbine meters, PD meters, magnetic flow meters, etc.
   a) Make sure that testing and flushing plans do not endanger instrumentation equipment.
   b) Instrument removal for testing and flushing shall be performed by properly trained workers.
   c) Tubing and wiring shall be carefully disconnected and reconnected without damage.
2. For control valves with bypass:
   a) Remove control valve and protect with a plastic bag, and replace with a spool piece.
   b) Flush through bypass, and then flush through block valves.
3. For control valves without bypass: Remove control valve and protect with a plastic bag, and replace with a spool piece to allow flushing.
4. Do not hydrostatically test control valves or pressure regulators. Such testing can damage the packing on control valves and diaphragms on regulators.
5. For instrument connections to transmitter gauges, local indicators and analyzer taps:
   a) Close the line block valve(s), and open vent and drain valves.
   b) Do not fill the instruments with water.
6. For PD and turbine meters:
   a) Remove meter and strainer basket before flushing and hydrostatic testing, and replace meter with spool piece.
   b) PD meters shall be filled with light oil to prevent corrosion during the storage period before their installation.
   c) If possible, do not install turbine meter and strainer basket until after the first product run to reduce the chance of damage from debris.
7. Do not install orifice plates and other flow elements (except venturi) until flushing and testing are complete.

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8. Blind or remove relief valves during flushing.

10. Loop Testing

When all individual loop components have been tested and calibration tested by the contractor and/or manufacturer, a complete function test of the instrument loop shall be made.

- The object of loop testing is to prove that the installed instrumentation functions correctly and is operational and ready for handing over to Mobil for plant commissioning.
- Mobil shall be notified of the testing so that each loop test may be witnessed by a Mobil representative.
- Loop testing shall be carried out as indicated below.
- Tests are based on CCI P/1.

10.1. General

Loop testing is carried out by a test "crew" with at least one person at the field instrument, and at least one at the central control console (or local panel or satellite house). Typically multiple field crews will test at the same time with support from single test crew at a console. Adequate radio communication facilities need to be in place to support testing.

- The control console testing shall be performed from the controller faceplate on a graphic display that will be used following plant commissioning.
- Where loop testing is taking place in a plant already in operation, a separate control console shall be used to avoid disruption to plant operation.
- Normally, loop testing is the first time the total loop operation is possible.
- Calibration check testing of loop transmitters, transducers and actuators shall have been completed before loop testing commences.
- All defects in apparatus, wiring and tubing connections shall have been eliminated during the various tests prior to loop testing.
- The loop shall be checked with all transmitters, transducers and actuators in place.
- For inputs, a simulation of the process variable is applied and read in the control room display (or local indicator).
- For outputs, the final action (e.g., control valve position) shall be checked against an output setting made at the DCS console (or local controller).
- Automatic controller action and logic shall also be tested.

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- It is preferable that a personal computer (or DCS console with PC emulation) shall be available in a central control room or satellite house to log all test results into a loop testing database.
- If an unsatisfactory loop test result is encountered, the relevant earlier tests shall be repeated, as necessary, after rework, replacement or repair. The loop test shall then be completely repeated for that particular loop.

10.2. Input Simulation

For DP and pressure transmitters used for indication and control, a hand-held instrument communicator can be used to simulate the output signal. For emergency shutdown transmitters and critical control loops, a hand held pressure calibrator shall be used to apply pressure to the instrument.

- Level transmitters and controllers are tested by filling the displacer cages with water.
- Thermocouples and RTDs are tested with a temperature simulator millivolt source and verified to read ambient temperature after re-connection.
- Filled-system temperature transmitters that have ranges at ambient temperature or boiling water point shall be checked at these temperatures. If the filled systems are for elevated temperatures, they shall be verified against a thermocouple or mercury thermometer when the process temperatures are brought up.

10.3. Programmable Electronic Systems (PES)

All PES (DCS, PLC, TMR PLC, etc.) hardware and software shall be functionally tested at a factory acceptance test prior to site delivery. The PES control scheme operation and settings shall be verified as an integral part of loop testing.

- All PES console face plates (or local panel controllers) shall be checked for correct location (in group displays and process schematics) and DCS tag name (or local nameplate).
- Control scheme configuration such as signal selection, cascade loop operation, tuning parameters, alarm settings, process interlock and shut down logic shall be checked for correct operation as per instrument loop drawings.
- All emergency shutdown systems inputs and output shall be tested and proved.
  - When interlock bypass inputs have been loop tested, these bypasses can be active to facilitate further testing.
  - The complete shutdown system shall then be checked for correct sequence of operation, and all output devices shall be shown to work in a satisfactory manner.
- Upon completion of loop testing all controllers, output switches and bypass switches shall be left in a non-active state with the correct action, tuning parameters and alarm settings as per instrument loop drawings/data sheets.

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10.4. Hazardous Zones

Where a part of the plant has been classified as a hazardous area (Division 1 or Division 2), caution is necessary if final loop testing is performed after the introduction of hydrocarbons, or other potentially hazardous material, into the plant. Such tests shall be under direct Mobil supervision.

- The appropriate national codes and local regulations shall be followed where a flameproof or explosion proof or safety purged enclosure needs to be opened to simulate operation. This normally involves a periodic gas test in the area. To avoid the possibility of explosion, power shall be switched off prior to removing and replacing enclosure covers.
- Where intrinsically safe circuits are used at field sensors, test equipment shall not infringe upon intrinsic safety certification.

10.5. Test Procedures

Following are testing guidelines that cover various situations.

1. Visually check field installation for completed wiring, piping, power and air supplies.
2. For continuous inputs:
   a) Manually apply process simulation for 0, 50 and 100 percent of input range.
   b) Check DCS indication (or local indicator) that measurement indication matches applied signal and response of other control loop components (e.g., alarming) is as designed.
3. For automatic control outputs:
   a) Put controller in manual and set output to 0, 50 and 100 percent.
   b) Check control valve moves according the output.
   c) Set output to 50 percent, applied process measurement simulation for 50 percent and switch to automatic.
   d) Check bumpless transfer, and confirm correct control valve movement on set point change.
4. For discrete (status, alarm, trip) inputs, simulate process conditions (if possible, otherwise , manually) to activate device. Check DCS indication and response of other control loop components (e.g., alarming) are as designed.
5. For discrete outputs, create the appropriate input conditions to activate the output, and validate final valve/actuator action takes place.
6. Test results shall be documented as per this Practice.

7. Test failures shall be noted for later recalibration and/or reconfiguration and a repeat loop test. Minor changes may be made immediately and the loop re-tested, but changes shall be documented for "as built" loop drawing update.

11. Test Administration and Documentation

The Mobil field engineer shall ensure that the contractor provides the following:

- A plan of all activities involved, including a Gantt Chart, prepared from a detailed estimate of the work hours and apparatus required for the total inspection, calibration test and loop testing tasks. This plan shall be regularly updated to reflect current progress.
- Adequately skilled manpower and technically/organizationally skilled supervision.
- Arrangements for the storage, facilities and equipment adequate to meet the size and time schedule of the job. These shall ensure safe storage and handling of all plant instrumentation without damage or deterioration and provide physical standards of the necessary quality and accuracy.
- Notification and follow-up on:
  - Anomalies and discrepancies in results
  - Identification of faulty instruments, components and materials
  - Process replacement or acceptable repair of defective items
  - Rework or modification of unacceptable installations with vendor or subcontractor

11.1. Inspection, Calibration and Loop Test Records

Accurate records are essential for the satisfactory, timely completion of this phase. In order to keep accurate records of all settings and work carried out, and subsequent rework and retest where applicable, an acceptable and mutually agreed upon form of documentation is necessary.

- Records shall preferably be kept in an appropriate PC database. Instrument maintenance packages that may be used for this purpose are: Honeywell Loveland's "Control Q" system, Fisher-Rosemount's "Asset Management System" or Applied Systems "Cornerstone".
  - If these packages are not available, a database using Microsoft Access or Excel shall be defined.
  - The database shall include: instrument data, calibration test results, inspection comments, orifice plate quality and dimensions, line dimensions, alarm and shutdown settings.

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- For instrument shop and control room loop testing, data shall preferably be entered directly in the database as the tests take place. If this is not possible, results shall be entered not later than 48 hours after the time of inspection or test.

11.2. Loop Acceptance

Upon completion of satisfactory testing of a group of loops (normally a process unit), the control loops shall be accepted by the Mobil operating company (or representative).

- An instrument loop check sheet shall be signed by the accepting party in addition to the tester and a test witness.
- Documentation shall be handed over at this stage.
- It is recommended that the test status be noted in the instrument test database.
- The database shall give ready information and reports on the completion status of loop testing and acceptance.

11.3. Forms

Contractors usually have their own forms that they prefer to use. However, if this is not the case, the following forms may be found in CCI P/1.

- Instrument Pre-Installation Calibration Sheet
- Instrument Loop Check Sheet
- Alarm System Check Sheet
- Calibration Check Sheet-Pressure Gauges, Dial Thermometers
- Safety Relief Valve-Test Report

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Winterizing & Heat Tracing

MP 00-P-04

July 1998

Scope

This Mobil Engineering Practice (MEP) contains the general requirements and methods used for permanent heating or winterizing of equipment and piping to provide protection from freezing, congealing or excessive increase in viscosity, to prevent formation of corrosive compounds due to water condensation or to prevent condensation of vapors or gases. The three basic types of heat tracing systems are discussed.

Table of Contents

Scope **1**

1. References **4**

1.1. MEPS–Mobil Engineering Practices 4

1.2. API–American Petroleum Institute 4

1.3. ASTM–American Society for Testing and Materials 4

1.4. NFPA–National Fire Protection Association 5

1.5. Additional References 5

2. Design Considerations **5**

2.1. Sensitive Areas 6

2.2. Alternatives 7

2.3. Protective Heating of Liquid 7

2.4. Instruments 7

2.5. Fuel Gas Systems 8

2.6. Sulfur Piping 8

2.7. Valves, Unions and Flanges 8

2.8. Nonjacketed Piping Systems 8

2.9. Safety Showers 8

2.10. Live Hose Reels 9

2.11. Fire Hydrants and Monitors 9

3. Heat Tracing Systems: Steam, Electric and Hot Oil **9**

3.1. System Types and Limitations 9

4. Design of Steam Tracing Systems **9**

4.1. Steam Supply 10

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4.2. Condensate Collection 10
4.3. Steam Tracers 11
4.4. Number of Steam Tracers 16
4.5. Steam Jacketing of Pipe 20
4.6. Steam Traps 20
4.7. Drawings 21
4.8. Tables 21
5. Electric Tracing 22
5.1. Area Classification and Materials Approval 22
5.2. Types of Electric Tracing Systems 22
5.3. Design Basis 24
5.4. Circuit Schedules and Description 28
5.5. Drawings 29
5.6. Specifications 29
6. Hot Oil Systems Equipment 30
6.1. Expansion Tank 30
6.2. Pumps 31
6.3. Heater 31
6.4. Controls 31
6.5. Materials 31
6.6. Heat Transfer Fluid 32
6.7. Tracers 32
6.8. Safety 32

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1. References

The following publications form a part of this Practice. Unless otherwise specified herein, use the latest edition.

1.1. MEPS–Mobil Engineering Practices

MP 00-P-10	Meteorological Data for Plant Design
MP 16-P-01	Piping-General Design
MP 16-P-31A	Piping-Classifications-(E&P, On/Offshore)
MP 16-P-40	Piping-Fabrication, Erection, Inspection, & Testing
MP 32-P-09	Heater Controls
MP 33-P-01	Electrical - General Requirements
MP 33-P-02	Electrical - Classification of Hazardous Locations
MP 33-P-29	Electrical - Testing & Commissioning
MP 34-P-10	Thermal Insulation - Hot Service
MP 41-P-08	Steam Disengaging Drums-Design & Fabrication

1.2. API–American Petroleum Institute

API SPEC 5L	Specification for Line Pipe Forty-First Edition
API RP 500	Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities First Edition (Supersedes RP 500A, RP 500B, RP 500C)

1.3. ASTM–American Society for Testing and Materials

ASTM A53	Standard Specification for Pipe, Steel, Black and Hot-Dipped, Zinc-Coated, Welded and Seamless
ASTM A179/A179M REV A	Standard Specification for Seamless Cold-Drawn Low-Carbon Steel Heat-Exchanger and Condenser Tubes E1-1996 R(1996)
ASTM A106	Standard Specification for Seamless Carbon Steel Pipe for High-Temperature Service

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ASTM A269	Standard Specification for Seamless and Welded Austenitic Stainless Steel Tubing for General Service
ASTM B75 REV A	Standard Specification for Seamless Copper Tube
ASTM B88	Standard Specification for Seamless Copper Water Tube

1.4. NFPA–National Fire Protection Association

NFPA 70	National Electrical Code 1996 Edition Errata #1; Tentative Interim Amendment 1996

1.5. Additional References

BS 6351	British Standards Institution: Electric Surface Heating

2. Design Considerations

The permanent heating or winterizing of equipment and piping shall be in accordance with requirements of this MEP, unless superceded by more stringent local regulations.

Protective heating shall conform to the requirements of the project specifications and this MEP.

- When economical and feasible, piping and equipment shall be designed so that protective heating is not required or can be minimized.

Equipment and piping containing liquids that will solidify or congeal during nonoperating periods shall be designed to be drained, flushed, blown, steamed out or cleaned, rather than heat traced solely for nonoperating conditions.

- The facilities design shall include mechanisms to ensure motive power sources for instrumentation, such as instrument air or gas, are adequately dried to maintain a water or hydrocarbon dew point at least 10°C (18°F) below the design minimum ambient temperature (at system operating pressure).
- The ambient design temperature for protective heating shall be the extreme low temperature unless otherwise specified by Mobil.
- The design wind velocity shall be the mean velocity for the winter season (as defined in **MP 00-P-10**).

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2.1. Sensitive Areas

Special attention shall be given to the following areas to determine if protective heating is required during startup, operation and shutdown periods. These areas, and similar areas not listed here, shall not be overlooked in systems that generally do not require protective heating.

1. Equipment and piping in water service when intermittent operation or minimum flow will not maintain the temperature above freezing.
2. Water seals.
3. Relief valves and their discharge lines.
4. Instrument leads, orifice taps and pressure taps.
5. Field instruments.
6. Auto-refrigeration at control valves and letdown stations.
7. Piping and equipment that may contain significant amounts of moisture during startup or upsets.
8. Undrained low points in equipment and piping and dead-ended pipes or legs.
9. Drains on pipelines, pumps, tanks, hydraulic power systems and other equipment.
10. Lube and seal oil systems.
11. Closed-system cooling water tanks for compressors in wet gas service.
12. Fuel oil tanks and lines.
13. Diesel-driven equipment, particularly fire pumps and emergency generators.
14. Concentrated sulfuric acid and caustic soda solutions as used in demineralized water treatment.
15. Drains and traps at low points in compressed air lines.
16. Fuel gas knockout pot drains.
17. Turbine inlet air systems.
18. Air or water exchangers in condensing service.
19. Natural gas cooler tubes if hydrate formation is possible.
20. Suction piping to compressors in saturated gas service.
21. Fire foam lines.
22. Aboveground fire water supply tanks.

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2.2. Alternatives

The following alternatives shall be considered in determining the optimum method of providing protective heating or winterization for piping and equipment:

1. Internal Heating: Coils for steam or other heating media, internal heat exchanger or electric resistance heating elements. Steam coils normally shall not be installed in equipment containing hydrocarbons above 93°C (200°F) in order to avoid the possibility of leaking condensate flashing into steam.
2. External Heating: Steam tracing, steam jacketing, electric tracing or panels, external heat exchanger, hot water jacket, or heated building or other enclosure.
3. Insulation.

For protection of pumps, the alternatives of external heating, circulation and draining shall be considered.

2.3. Protective Heating of Liquid

Vessels and piping require protective heating of the liquid space only.

- Vessels in acid or other severely corrosive service shall be heated only on the external surface.
- Precautions shall be taken in determining maximum allowable temperature for vessels in acid service because this temperature varies with material used and acid concentrations. The maximum allowable temperature in carbon steel vessels that are not stress relieved and contain amine or caustic is 38°C (100°F). Higher temperatures may cause corrosion or embrittlement problems.

In vessels containing water as a separated fluid, heating normally shall be limited to the water draw-off boot.

- Heat is required over the entire bottom of vessels when there is the possibility of refrigeration effect from the expansion of light hydrocarbon liquids.
- The presence of a flare knockout drum is an example of when refrigeration effect must be considered.

2.4. Instruments

Winterization and heat tracing of instruments shall be in accordance with this Practice. Each instrument shall be separately heat traced and not included in other tracing systems.

Precautions shall be taken not to overheat, to the point of vaporization, instrumentation and instrument tubing that contain bubble point fluids. Overheating could cause equipment to function improperly.

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2.5. Fuel Gas Systems

Refinery fuel gas systems shall be heat traced from local knockout drums to the outlet of burner manifolds to prevent condensation of C_3 and heavier components.

When propane or heavier hydrocarbons in concentration above 50 percent are burned, vaporizers shall be required in the knockout drum (in addition to the heat tracing).

2.6. Sulfur Piping

Sulfur piping shall be steam jacketed or may be steam traced using heat transfer cement.

- The steam temperature shall be selected to prevent overheating of sulfur lines and solidification of the sulfur.
- Liquid sulfur shall be maintained between 121°C and 149°C (250°F and 300°F) unless stipulated otherwise by the project specifications.

2.7. Valves, Unions and Flanges

Where piping systems are heat traced, the valves, unions and flanges are usually not traced and insulated to prevent freezing. The need to trace and insulate these items to control viscosity shall also be considered carefully. The project specifications shall stipulate the extent of heat protection required on the basis of the climatic conditions at the project site.

Electric heating controlled by a thermostat is intermittent. Therefore, the need for insulating valves, unions, and flanges is greater in electric tracing than in steam traced systems. Process stream sensitivity to temperature, required accuracy of temperature control and overall economy normally determine whether these items shall be insulated.

2.8. Nonjacketed Piping Systems

Nonjacketed piping systems containing products such as sulfur, maleic anhydride and other substances whose temperatures must be accurately controlled shall be supported by insulated shoes or hangers designed to prevent heat transfer between the pipe and the steel supports. Pipe "dummy" legs shall be traced, insulated and supported in the same manner as the pipe. Supports for pipe ells at grade shall be insulated.

2.9. Safety Showers

Safety showers and eyewash fountains installed outdoors where freezing conditions may occur shall be made freezeproof. Freezeproofing shall be accomplished by utilizing self-draining equipment or with thermostatically controlled low-voltage electric heating.

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In locations that experience prolonged freezing conditions, thermostatically controlled low-voltage electric heating shall be used. Outdoor bathtubs in acid units shall be maintained at 21°C (70°F) minimum and 32°C (90°F) maximum.

2.10. Live Hose Reels

Where freezing temperatures may occur, live hose reels shall be installed in a heated enclosure. Temperature-controlled electric heating or a self-draining steam coil may be used.

- When a steam coil is used, all piping connections and the steam trap shall be installed outside the enclosure.
- Steam leaks inside the enclosure cause deterioration of the hoses or the enclosure.

2.11. Fire Hydrants and Monitors

Fire hydrants and monitors shall be provided with self-draining valves below the frost line. Where drain valves cannot be installed below the frost line, the hydrants or monitors shall be heat traced and insulated.

3. Heat Tracing Systems: Steam, Electric and Hot Oil

3.1. System Types and Limitations

Steam tracing is limited to applications that permit relatively wide temperature variations. It can be used in hazardous areas and defects are usually easily located and repaired.

Electric tracing provides more accurate temperature control. Certain types cannot be used in all classified areas and defects are usually more difficult to locate.

Hot oil systems provide accurate temperature control where high temperatures are required.

4. Design of Steam Tracing Systems

Steam tracing installations shall be laid out in an orderly manner with provision for thermal expansion and easy access to all flanges, unions, valves, traps, strainers and instruments. Valves and flanges, unions or tubing fittings shall be provided at traps so that they can be tested and readily removed.

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Steam tracer supply and condensate return piping shall be valved.

- The valves shall be accessible with a ladder or, preferably, from a platform. When possible, supply valves shall be grouped together to facilitate shutoff during summer and maintenance during winter months.
- Where header block valves are not accessible, secondary valves that are accessible shall be provided. The location and installation of these secondary valves shall be subject to Mobil approval.

All piping components shall conform to MP 16-P-31A.

4.1. Steam Supply

Steam shall be supplied to a group of tracers by a short subheader located above the highest point to be traced unless otherwise approved by Mobil.

- All subheaders shall be connected to the top of the steam supply main with a valved connection and shall be trapped.
- Each tracer shall have a takeoff valve at the subheader.
- All subheaders shall be sized for 25 percent additional tracers. Couplings or plugged connections for future tracers are not required but are recommended.

4.2. Condensate Collection

- Steam tracings systems shall include a condensate system for energy conservation where economically justified or necessary to comply with environmental regulations.
  - Separate condensate systems shall be provided for different steam pressures.
  - Economics for the system shall consider the differentials in water makeup and treating, pumping, heat energy and effluent water treatment and disposal.
  - Condensate system design shall be in accordance with MP 41-P-08.
- Condensate collection manifolds shall be located to permit gravity flow of condensate and shall be located below the tracer discharge where possible.
  - If the manifold is located overhead, the risers shall be insulated and provision shall be made for draining the manifold when the tracers are shut down.
  - Condensate headers and connections to mains shall, at minimum, be sized on the assumption that at least 20 percent of the connected traps will fail fully open.
- Condensate return lines from traps are subject to freezing in cold climates if the condensate load is low. Therefore, the load and heat loss from condensate return lines shall be carefully determined to prevent freezing.

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- Condensate lines shall be sized to prevent excessive back pressure from two-phased flow and ensure proper trap operation.
- A block valve shall be located where the condensate header connects to the condensate main.

4.3. Steam Tracers

Table 1 contains allowable working pressures at various temperatures for commonly used tracer materials, thicknesses and sizes.

- It is preferred that tracers for long, comparatively straight runs [piping 90 m (300 ft) minimum] to be seamless Schedule 40 steel pipe conforming to Grade B of API SPEC 5L, ASTM A53 or ASTM A106, using Class 3000 socket welded steel fittings.
- Tracers smaller than 13 mm ($^1/_2$ in) OD tubing are permitted only for the winterizing of instrumentation. Tracers smaller than 10 mm ($^3/_8$ in) OD shall not be used without prior Mobil approval.

Tracers for other piping and for equipment shall be annealed copper tubing if the following apply:

- The metal temperature of the tracer is 230°C (450° F) or less.
- The environment is not corrosive to copper.

Copper tubing shall conform to ASTM B88, Type K or ASTM B75M with wall thickness equal to ASTM B88, Type K.

Table 1: Allowable Working Pressures for Tracers

Material	**Wall Thickness, inches (See Note)**	**OD, inches °F:**	**Allowable Working Pressures, psig Maximum Tracer Metal Temperatures**								
			250	**300**	**350**	**400**	**450**	**500**	**600**	**650**	**700**
Annealed	Type K	$^3/_8$	775	775	650	475	225	125			
Copper		$^1/_2$	850	825	700	525	250	125			
Tubing B88		$^3/_4$	575	550	475	350	175	75			
Annealed	0.049	$^1/_2$	850	825	700	525	250	125			
Copper	0.049	$^3/_4$	575	550	475	350	175	75			
Tubing B75	0.065	1	575	550	475	350	175	75			
Seamless SS	0.035	$^3/_8$	2800	2800	2700	2600	2500	2400	2250	2200	2150
Tubing A269	0.035	$^1/_2$	2100	2100	2025	1950	1875	1800	1700	1650	1625

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Material	Wall Thickness, inches (See Note)	OD, inches °F:	Allowable Working Pressures, psig Maximum Tracer Metal Temperatures								
			250	300	350	400	450	500	600	650	700
TP304, TP304L	0.049	3/4	1950	1950	1875	1800	1750	1675	1575	1550	1500
TP316, TP316L	0.065	1	2150	2150	2075	2000	1925	1850	1750	1700	1675
Seamless	0.035	1/2	2025	1975	1925	1875	1825	1775	1675	1650	1600
Carbon Steel	0.049	3/4	1900	1850	1800	1750	1700	1650	1575	1525	1500
Tubing A179	0.065	1	1875	1825	1800	1750	1700	1650	1550	1525	1475
Seamless	Sch 40	NPS 1/2	2250	2250	2250	2250	2175	2125	1950	1900	1850
Carbon Steel	Sch 40	NPS 3/4	1925	1925	1925	1925	1875	1825	1650	1625	1575
Pipe A53-B	0.05 in CA	NPS 1	2100	2100	2100	2100	2025	1975	1800	1775	1725

Conversion Factors: Inches to millimeters: 25.4; psig to kPa: 6.895; °F to °C: (°F–32)/1.8.

NOTE: These thicknesses are minimums. Only the thicknesses for carbon steel pipe include a corrosion allowance.

4.3.1. Seamless Stainless Steel Tubing

Seamless stainless steel tubing conforming to ASTM A269 (Types 304, 316, 304L and 316L are acceptable) shall generally be used where tracer metal temperatures exceed 230°C (450°F) and in environments corrosive to copper.

Carbon steel tubing (conforming to ASTM A179/A179M REV A) may be considered as a substitute for stainless steel, with Mobil approval, for applications that operate year round at metal temperatures 120°C (250°F) and higher.

4.3.2. Thermal Expansion

Thermal expansion of tracers will be greater than that of the traced line.

Expansion loops will be required on straight, horizontal runs exceeding 18 m (60 ft) for steel tracers and 12 m (40 ft) for copper and stainless steel tracers.

- Expansion loops shall be either 360 degree ovals or U-shaped.
- It is preferred that expansion loops be in the horizontal plane at the same elevation as the rest of the tracer to avoid pockets where condensate may collect.
  - Expansion loops may be installed vertically upward when space does not permit horizontal installation.

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  - The 360 degree loop shall be installed only horizontally.
  - For vertical lines, expansion loops shall be U-shaped and self-draining.

- Expansion loops usually are not insulated except for personnel protection. In climates where heat loss is expected to cause freezing of uninsulated loops, they shall be insulated.

4.3.3. Tracing Piperuns

When tracing long piperuns, lengths of stainless steel (and carbon steel) tubing shall be assembled using silver soldered couplings of the same material as the tubing. Lengths of copper tubing shall be joined using brass bite-type compression tubing unions (Swagelok or equal.) These tubing unions shall be located outside the insulation at the outboard side of an expansion loop.

Tracers on horizontal piping normally shall be located on the lower portion of the pipe (preferably at 5 or 7 o'clock).

- When multiple tracers are necessary, they shall be located on the lower half of the pipe at 30 degrees on either side of the vertical centerline.
- Carbon steel tracers shall be attached to piping with stainless steel bands at maximum intervals of 1000 mm (40 in).
- Tracers of copper per tubing shall be attached with soft No. 14 copper wire or copper bands at 1000 mm (40 in) intervals.

Except as stated in the following paragraph, physical contact between the tracer and pipe is required for good heat conductivity and is especially important for materials with a high freezing point.

On caustic, amine or acid lines and equipment—or to prevent boiling of saturated liquids in instrument leads, level controls and similar instruments—tracers shall be blocked away from the lines by use of nonconductive standoff. This procedure prevents transferring excessive heat, which results in "hot spots."

Additionally, the tracers may be wrapped with insulating tape to reduce the heat transfer. Standoffs shall be spaced at 600 mm (24 in) intervals.

4.3.4. Heat Transfer Cement

Heat transfer cement improves the heat transfer from the tracer to the traced equipment and usually permits the use of smaller or fewer tracers.

- When more than one tracer is required, the economics of using heat transfer cement shall be studied.

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- Manufacturer's recommendations relating to surface preparation and installation shall be strictly followed.
- Such tracers shall be attached to piping with stainless steel bands at maximum intervals of 380 mm (15 in).

Steam tracers utilizing heat transfer cement shall be installed parallel to the process line and be located on the most accessible surface of the line, rather than on the bottom section.

- The reduction in heat transfer efficiency due to tracer location is very small when heat transfer cement is used.
- Therefore, accessibility becomes more important than location because the former results on lower installation and maintenance costs.

Heat transfer cement is used in special applications such as polymer service, where, the setting point of the polymers usually ranges from 50°C to 75°C (122°F to 167°F). The conduit skin temperature shall be maintained safety above the maximum setting point temperature to prevent localized surface freezing and degradation of the solidified material at the pipe wall.

4.3.5. Spiral Wrapping

Spiral wrapping of tracing is not permitted without prior Mobil approval. Spiral wrapping shall be self-draining and installed to make allowance for the difference in the coefficient of expansion of the tracer and the item traced. The total vertical height shall be accounted for in vertical spiral tracing (see Section 4.3.11).

4.3.6. Blankets

On vessels, large pumps, large piping (>NPS 30), specialty items and large valves, tracing shall be "blanketed." Blankets consist of tracing made up in accordion fashion and strapped in such a manner as to allow the tracing and item being traced to expand while maintaining intimate contact, and be self-draining. Consideration shall be given to using commercial sheets or flexible panels.

4.3.7. Trapping

Tracers, including each branch tracer, shall be individually trapped.

4.3.8. Winterizing

For simple winterizing situations, the tracer shall be routed past valves and flanges in the same plane as the rest of the tracer without creating pockets. The tracer shall be bent to follow the general contour of the valve body and the flanged joints.

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4.3.9. Corrosion-Resistant Metal Tags

Corrosion-resistant metal tags shall be provided at both ends of each tracer, at the trap and at the supply valves. These tags shall be stainless steel and stamped with the traced line or equipment number, as well as the tracer number.

4.3.10. Index

An index shall be prepared which indicates the tracer numbers and the lines they service. This index can be used as a checkoff list for monitoring the operation or traps and for turning the tracers off or on in the spring and fall.

4.3.11. Height

When feasible, tracers shall start at a high point and be self-draining.

Sufficient unions shall be provided to permit removal of piping components (valves, instruments, other piping specialty items) without the removal of the tracer itself. All such unions shall be installed outside the insulation.

A single manifold tap shall not be used for multiple tracers.

In steam tracing circuits, it is necessary to consider the total amount of vertical height of all pockets. This total shall not exceed the allowable total vertical rise as calculated by the following formula:

$$Hv = 10\%(KPs)$$

Where:

Hv = total vertical rise in m (ft)

Ps = inlet steam header pressure in kPag (psig)

K = dimensional constant

0.102 m/kPag for metric (SI) units

2.31 ft/psig for customary units

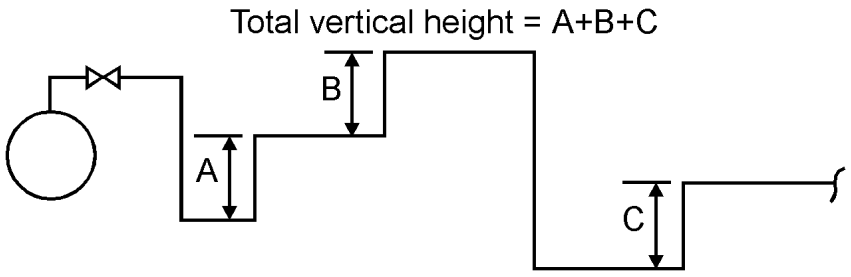

Figure 1: Height

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4.4. Number of Steam Tracers

The number and diameter of steam tracers required can be determined from the curves in Figures 2 and 3. For freeze protection applications, the product temperature shall be assumed to be 10°C (50°F).

Table 2: Example for Determining the Number and Diameter of Steam Tracers

Steam temperature	=	160°C (320°F)
Product temperature	=	70°C (158°F)
Extreme low temperature (minimum ambient design temperature from MP 00-P-10)	=	0°C (32°F)
Nominal pipe size	=	12 in
Insulation	=	50 mm (2 in) thick (fiberglass)
Wind velocity	=	16 km/h (10 mph)

4.4.1. Step 1

Subtract the extreme low temperature from the product temperature (subzero temperatures are subtracted algebraically):

70°C–0°C = 70°C

or

158°F–32°F = 126°F

4.4.2. Step 2

Locate 70°C (126°F) at the bottom of Figure 2. Follow the 70°C (126°F) line vertically until it intersects the line for NPS 12 pipe. Project this point of intersection horizontally to the left side of the chart and read $J_R(Q_R)$ = 75,000 J (Btu).

4.4.3. Step 3

Multiply $J_R(Q_R)$ by the following factors from Figures 2 and 3:

M_1= 1.00, insulation thickness, from Figure 2

M_2= 0.675, insulation material, from Figure 2

M_3= 1.07, wind velocity, from Figure 3

Thus:

$$J_r(Q_R) \times M_1 \times M_2 \times M_3 = J_1(Q_1)$$
$$75{,}000 \times 1.00 \times 0.675 \times 1.07 = 54{,}169 \text{ J}$$

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or
70 x 1.00 x 0.675x 1.07= 50.6 Btu

4.4.4. Step 4

Subtract the temperature of the fluid in the pipe from the steam temperature:

160°C–70°C = 90°C
or
320°F–158°F = 162°F

4.4.5. Step 5

Enter the bottom of Figure 3 at 90°C (162°F). Follow the 90°C (162°F) line vertically until it intersects the horizontal line of 54,169j (50.6 Btu) from the left side of the chart. This intersection lies on the line for one NPS $^{5}/_{8}$ pipe tracer. Use the NPS $^{5}/_{8}$ tracer.

The maximum length for tracers may be obtained from Table 3. Where many long runs are involved, however, it may be more economical to calculate the tracer lengths instead of using the table.

Table 3: Steam Tracer Lengths

	Tracer Size					
	Steel Pipe			**Tubing**		
Steam Pressure and Temperature	**NPS 1**	**NPS $^{3}/_{4}$**	**NPS $^{1}/_{2}$**	**20 mm ($^{3}/_{4}$ in)**	**12 mm ($^{1}/_{2}$ in)**	**10 mm ($^{3}/_{8}$ in)**
683 kPa gauge & 150°C (99 psig and lower & 300°F)	122 m (400 ft)	91 m (300 ft)	60 m) (200 ft	91 m (300 ft)	60 m (200 ft)	18 m (60 ft)
689 kPa gauge & 170°C (100 psig and higher & 340°F)	183 m (600 ft)	155 m (500 ft)	122 m (400 ft)	122 m (400 ft)	91 m (300 ft)	18 m (60 ft)

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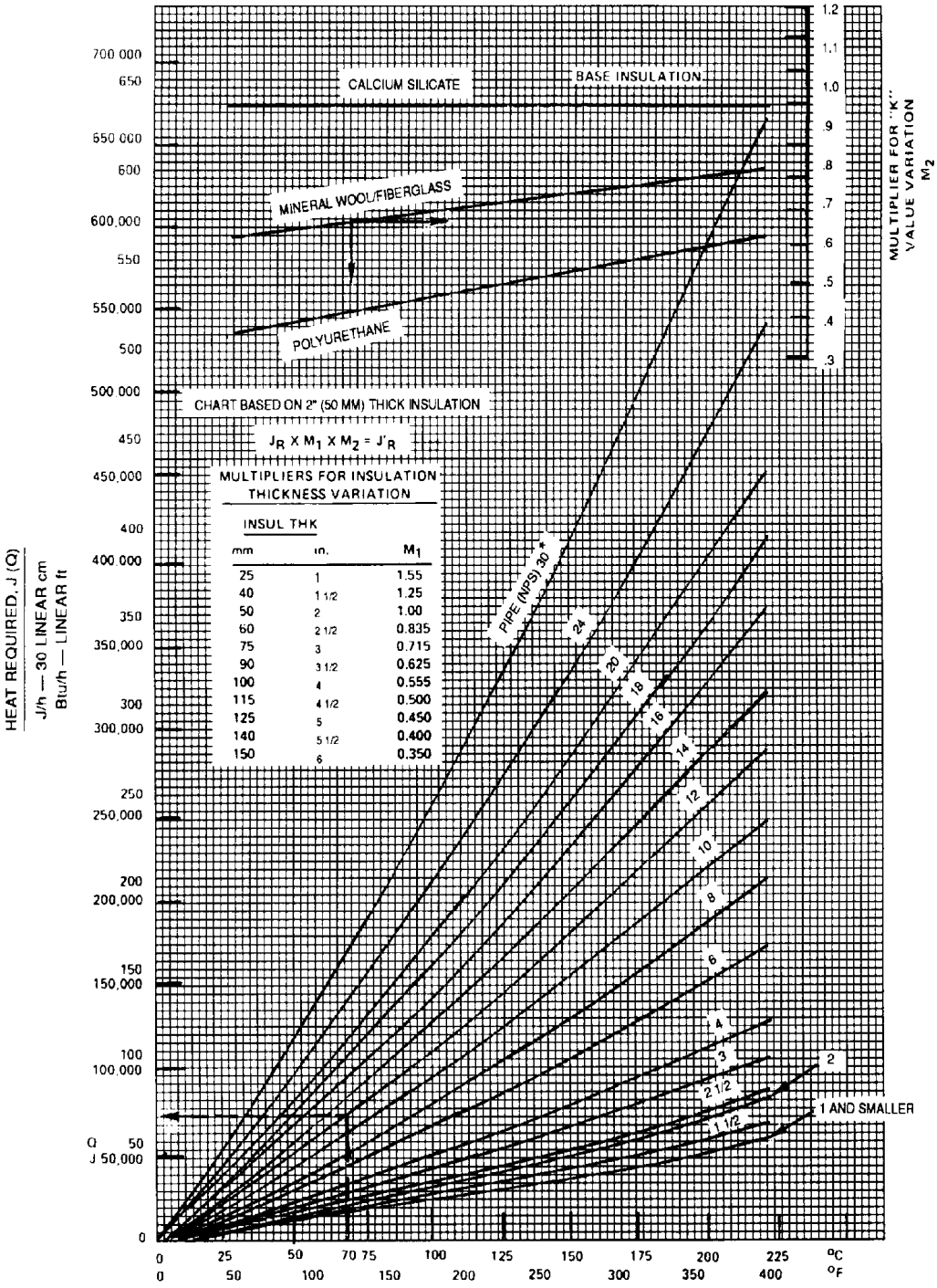

Figure 2: Heat Loss by Fluid Media

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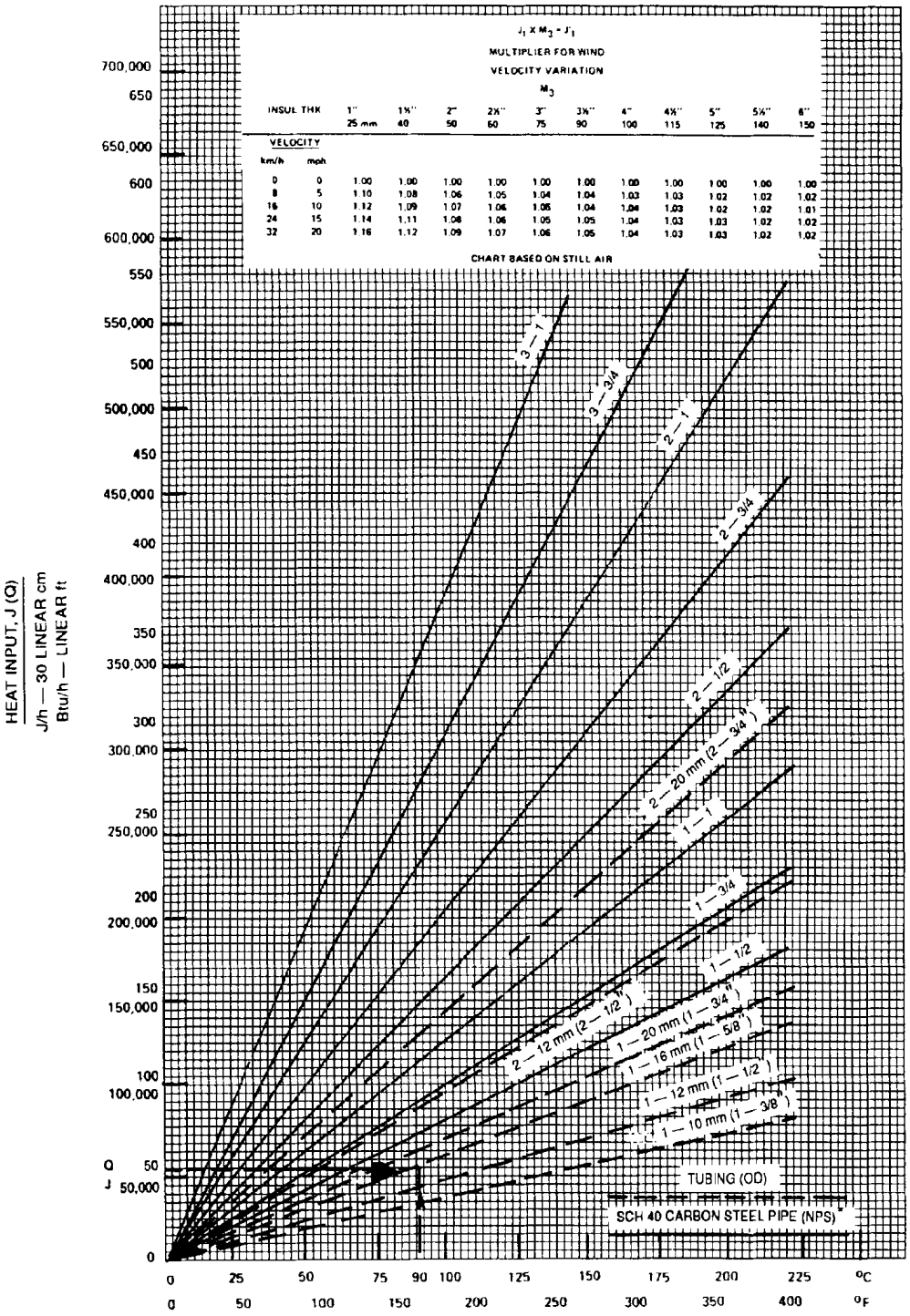

Figure 3: Heat Gained by Heat Tracing

4.5. Steam Jacketing of Pipe

The length of jacket shall be limited to reasonable fabrication lengths. In freezing climates, each 12 m (40 ft) of jacket length shall drain to s trap. In nonfreezing climates, jackets may be connected in series up to the maximum jacket length of 40 m (130 ft) between traps. Impingement plates shall be provided on the jacketed line at the steam entrance to prevent erosion.

4.6. Steam Traps

All traps shall be installed with strainers at the inlet or with full-size strainers and blowdown valves unless otherwise required by the project specifications.

- Traps with built-in strainers shall be avoided because they are sometimes too small and are subject to plugging.
- Strainers shall be sized for retention of construction debris only.
- All traps shall have stainless steel internal parts.

Suitable traps are available for all steam pressures.

- Inverted bucket traps are preferred because of their long life, reliability, efficiency and relative insensitivity to dirt and scale.
- Thermodynamic and thermostatic traps shall not be used for back pressures greater than 50 percent of the inlet pressure. Generally, both thermodynamic and thermostatic traps are susceptible to rapid wear and consequent failure.
- Trap selection shall be of the same type as existing plant trap inventory where possible.

Where possible, all traps shall be installed vertically, discharging downward for freeze protection during shutdown or failure. For horizontal installation the piping shall be pitched slightly downward for free drainage and traps shall be placed on their sides.

- Long drain legs shall be avoided but, when required, shall be insulated to prevent freeze-up.
- Tubing may be used for short trap discharges [1.8 m (6 ft)] if properly sized and routed to a drain funnel.
- The trap manufacturer's recommendation shall preclude any other specification.

Piping design associated with traps shall include sufficient block valves to facilities replacement/repair. Where traps cannot be easily monitored for proper operation, the installation of a test valve shall be considered.

Insulation for steam traced lines shall conform to the requirements of MP 34-P-10. The extra space requirement for the tracer shall be obtained by using oversized insulation or tracer-type insulation with extended legs.

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4.7. Drawings

Standard drawings shall be furnished to w show the following:

1. Straight, single steam tracer runs with expansion loops.
2. Dual and triple tracer installations.
3. Anchor and guide installations.
4. Traced valves.
5. Traced flanges and unions.
6. Traced pump casings and vessel drawoff pots.
7. Traced takeoff and block valves for instruments.
8. Types of connections between tracer tubing and pipe and flanges and valves.
9. Traced instruments–all types on the project.
10. Jacketing details at flanges, fittings and valves.
11. Details of standoff attachment of tracers.
12. "Blanketing" or flexible panel installations.

4.8. Tables

Tables shall be prepared which indicate:

1. The maximum length of tracer.
2. Supply pressure.
3. Condensate pressure.
4. Number of tracers.
5. Tracer size.
6. Total vertical height.
7. Traced line size.
8. Normal line.
9. Temperature.
10. Insulation thickness.
11. Minimum and maximum acceptable fluid temperatures.

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5. Electric Tracing

Electrical facilities shall be designed and installed in accordance with MP 33-P-01. Testing shall be in accordance with MP 33-P-29 and manufactures' recommendations.

5.1. Area Classification and Materials Approval

Electric heat tracing system components shall be approved by a recognized testing laboratory, such as the Underwriters Laboratory or Factory Mutual Corporation, for the specific classified area in which the system will be used.

Classified areas that contain electric heat tracing systems shall be indicated on a plot drawing that designates the boundary of each classification in accordance with MP 33-P-02 and API RP 500 (A, B, C).

In classified areas, electric tracing components and installation methods shall comply with Articles 427 500, and 501 of NFPA 70.

5.2. Types of Electric Tracing Systems

The types of electric tracing systems that shall be considered are outlined in the following Sections.

5.2.1. Parallel Resistance and Series Resistance Heating Cables

Parallel resistance and series resistance heating cables are constant wattage systems that can provide process control temperatures from 21°C to 163°C (70°F to 325°F) and shall be used with thermostatic controls to prevent overheating. Voltages for these systems range from 120 AC to 600 AC for lengths up to 2700 m (9000 ft).

5.2.2. Self-Limiting Heating Cables

Self-limiting heater cables are variable wattage systems that generate heat from the flow of electric current through a semiconducting thermoplastic material between two copper wires. The reduction in current flow is proportional to temperature, reaching an equilibrium within the strip's rating.

- This type of tracing system operates on voltages from 120 AC to 600 AC for lengths up to 2700 m (9000 ft), and process control temperature can be maintained up to 149°C (300°F).
- In some cases, the use of thermostats is optional with this system.

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Care shall be taken during installation to avoid damage to cable, to avoid water infiltration of splices and connections and to ensure that connections are waterproofed. There exists a potential for fires caused when the internal self-regulating semiconductive core becomes exposed to moisture, resulting in a high-impedance electrical fault with high thermal energy. The current level is normally insufficient to trip the protective branch circuit breaker.

- The system shall be a solidly grounded network, as opposed to an underground or high resistance network, and shall be provided with ground fault interrupter (GFI) and/or equipment protection devices (EPD).
- In some locations, local codes may require the use of residual current protection with trip indication to safeguard against high-impedance electrical faults (BS 6351).
- Prior to being placed in service, all circuits shall be tested in accordance with the manufacturer's recommendations.

5.2.3. Skin Effect Current Tracing System (SECT)

The SECT system is a constant wattage system consisting of a small diameter carbon steel pipe or heat tube, either connected by means of heat transfer cement or skip welded to the pipe to be heated. An insulated copper cable is contained inside the heat tube and is bonded to the pipe at the end. The heat tube is part of the circuit and becomes the heating element.

- The system voltage is directly proportional to the length of the heated pipeline and is between 0.1 V and 0.2 V per 30 cm (12 in) of pipe.
- The system can be installed below ground or aboveground and can be grounded without affecting cathodic protection systems.

When welding the heat tube to piping, care shall be taken to avoid locations where moisture can collect and cause corrosion. Welding to high-strength, low-alloy piping shall be done only with prior Mobil approval. All welding shall conform to MP 16-P-40.

The SECT system is suitable for long rundown or transfer lines [600 m (2000 ft) or longer] with few valves and flanges. The process temperature of the system is limited to 149°C (300°F) maximum.

5.2.4. Solid Metal Sheath—Mineral Insulated System

This constant wattage system consists of a solid metal sheath of copper, stainless steel or Inconel containing one or two conductors separated by mineral insulation. The conductors are resistance heating elements with operating voltages up to 600V AC. The type of sheathing shall be selected to resist corrosive atmospheres. Thermostatic control shall be used with this system.

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Metal sheathed heating cable shall be any of the following types:

1. Mineral insulated, stainless steel sheathed, alloy conductor (one or two conductors). Sheath temperature is limited to 427°C (800°F). Process temperature to be maintained is limited to 260°C (500° F).

2. Mineral insulated, copper alloy sheathed, alloy conductor (one or two conductors). Sheath temperature is limited to 249°C (480°F). Process temperature to be maintained is limited to 120°C (250° F).

3. Mineral insulated, Inconel 600 sheathed, alloy conductor (one or two conductors). Sheath temperature is limited to 649°C (1200°F). Process temperature to be maintained is limited to 427°C (800° F).

5.2.5. Other Systems

Other electric tracing systems may be considered with prior Mobil approval.

5.3. Design Basis

An electric heat tracing system shall be engineered carefully because an electric tracer can only produce a given amount of heat. All potential heat losses in the system (including pipe support shoes, drain and vent connections, flanges and valves) shall be considered. It is also important to consider all of the conditions to which the traced line might be subjected since high temperatures can destroy the covering of some tracer systems if not designed properly. When steamout of lines is expected, tracing shall be rated for the highest expected steam temperature, including any superheat.

1. Electric heat tracing systems shall be designed to performed one or more of the following functions:

   a) Maintain the minimum processing or operating temperature.

   b) Sustain fluid flow under minimum flow and ambient conditions.

   c) Prevent freezing in utility lines.

   d) In critical services, provide for an increased heating capacity to liquefy congealed or solidified material at ambient temperature in a line within eight hours, unless otherwise specified in the project specifications. (Critical services are those in which freezing of the material could cause a failure, resulting in safety hazards or extensive damage to equipment.)

2. When the tracer system is being engineered, the following information must be known:

   a) Desired pipe maintenance temperature.

   b) Minimum design ambient temperature.

   c) Maximum process or exposure temperature.

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d) Pipe diameter.

e) Pipe location (indoors/outdoors).

f) Material of pipe construction.

g) Pipe lengths and configuration.

h) Thermal insulation type and thickness.

i) Available supply voltage.

j) Electrical area classification.

k) Chemical environment.

3. Applied watts per unit length (metric or customary) shall be 125 percent of calculated required watts per unit length (metric or customary) to cover heat transfer efficiency and a factor of safety.

4. Electric tracing in critical or safety services such as safety showers and eyewash fountains, and where required in hazardous areas, shall be thermostatically controlled. Set points shall be indicated on the electrical heater schedules. All thermostat switch enclosures shall be in accordance with the classification of the area in which they are located. Control temperature adjustment shall be possible without opening the enclosure of Class 1, Division 1 or 2 equipment.

5. Safety shower and eyewash fountain piping shall include a redundant thermostat for high-temperature cutoff at 32°C (90°F).

6. Separately controlled heating circuits shall be provided on dead-end legs, closed bypasses, drain lines, instruments and spared pump piping. These stagnant conditions have a heat requirement cycle different from that of adjacent flowing lines.

7. Where circuit current exceeds the ampere rating of the thermostat contacts, the thermostat shall be used in conjunction with a suitably rated contractor.

8. The thermostat capillary shall be protected inside the insulation by fastening it to prevent tension on the capillary.

9. The thermostat bulb shall be located near the downstream end of the sections of traced piped or in another area likely to have the lowest temperature in the system being traced.

10. Thermostat sensing bulbs shall be installed with the bulb against the pipe at least 90 degrees from the heater cable, strapped firmly to the pipe. Use the vendor's recommendations for strapping material suitable for the temperatures involved.

11. Electric tracers shall be installed in the lower half of horizontal pipe runs. If there is more than one cable, they shall be located in the lower half approximately 30 degrees on either side of the vertical centerline. The cable shall not cross other tracers or touch itself, unless explicitly permitted by the manufacturer's specifications.

12. Design details for insulating and heat tracing valves, flanges, instruments and other process equipment in the piping system shall be indicated separately, and heat tracer lengths shall be increased accordingly. Details for the heating of connecting pipe

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branches and stub supports that may require supplemental heat also shall be given separately. Such connections shall be helically traced with a minimum tracer length of 900 mm (36 in).

13. Heat tracing tapes shall be fastened with double banding at all ends and splice points and at 600 mm (24 in) spacing along their length. Sufficient slack shall be provided for thermal expansion at these points. Heating tape shall be secured to pipelines by the use of adhesive tape of 13 mm ($^1/_2$ in) wide glass cloth, pressure sensitive with thermosetting adhesive, or equal. For securing heating tape to vessels and tanks, the adhesive tape shall be 50 mm (2 in) wide and manufactured from high-tensile, aluminum foil coated, fire-retardant acrylic with pressure-sensitive adhesive, or equal.

14. Cable end seals and power points for self-limiting heating cables shall be installed on the upper half of horizontal pipe runs to minimize the possible entry of water into the fittings. When the semiconducting core is exposed at joints, it shall be sealed with an RTV compound.

15. A standard monitoring system that is compatible with the type of heating cable used shall be employed. An indicator, such as light-emitting diode assembly (pilot lamp), shall be installed to monitor the cable length in each circuit to visually verify circuit operation. Careful consideration shall be given to the type of heating cable to be monitored and to centralizing the monitoring with the power distribution system. Where possible, the alarm system, monitoring and power distribution shall be housed in a single enclosure. The enclosure shall be suitable for the area classification. Additionally, the monitoring system shall comply with the following:

    a) Heating elements of the parallel resistance cables cannot be current monitored effectively. Only the condition of the bus wires or ribbons can be monitored. Thus, the parallel heating cables shall not be current monitored but only condition monitored by lamps.

    b) Monitoring of the series resistance heating cables shall be done with ammeters and/or current sensing relays.

    c) Ammeters shall be furnished for each heating circuit and may be direct-reading up to 10 A. Above 10 A, current transformers shall be used with ammeters.

    d) Means shall be provided to close or bypass thermostat contacts so that the heating circuit can be energized and current checked at any time.

    e) Ammeters shall be grouped and panel mounted wherever possible.

    f) Current measuring devices shall be provided to monitor functions of series resistance tracing heaters. The current sensing alarm monitoring system shall function on the basis of no current flow in the heating circuit when the control thermostat contacts are closed.

    g) Self-limiting heating cable systems shall be provided with monitoring equipment that will detect cable failures associated with ground fault and loss of continuity.

16. Caution labels shall be attached to electrically heated pipelines and equipment components at sufficiently frequent intervals to alert personnel. (Refer to Mobil Management Guide 03-1203: Safety and Health Sign Program; M&R (US) Marketing Safety Department, Fairfax, VA.) At minimum, caution signs shall be

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installed along traced pipelined at 7.6 m (25 ft) intervals. Short tie-lines and associated control devices shall be labeled. Adhesive-backed signs shall also be banded to the line or equipment.

17. Panelboards for control of heating loads shall be located in the area to be served and shall be conveniently accessible for operation. Panelboards shall have circuit breakers rated for branch circuit protection. Circuit protection and sizing for electric heat tracing shall be based on the minimum initial current at the lowest design temperature. Under specific load conditions, circuit breakers shall not exceed 40 A. Circuit loading shall not exceed 80 percent of the circuit breaker rating. Panelboards shall be provided with one spare circuit position for each five active circuits. Panelboards shall be provided with a directory indicating the circuit numbers and serviced heaters. A permanent, engraved nameplate shall be provided; it shall be marked "Heat Tracing" and shall include identification. Where ground systems are used, ground fault protection shall be included as part of the branch circuit protection, especially where tracing is used on safety showers or eyewash fountains.

18. All insulated piping systems and equipment with electric heat tracing shall be insulated in accordance with MP 34-P-10. To avoid damaging the tape, the insulation work shall be done immediately after the tracing tape has been installed.

19. Pipe insulation shall be placed so that flat electric heat tracing tapes are not exposed at half joints and bends. All gaps and voids shall be filled before the weatherproof cover is installed. Oversized piping insulation is not required with flat tapes.

    Particular care shall be taken where the tracing tape passes through the insulation protection cover to avoid damage to the tape outer sheath. Special-purpose cable glands shall be pop riveted to the insulation cover to ensure a secure entry of the tape. Similar care shall be taken at other places where the insulation cover may interfere with the tape (at valve flanges, for example).

20. Provision shall be made in the heat tracing system for removal of instruments and other equipment likely to require frequent maintenance or calibration. This shall be possible without cutting the heat tracing tape and with only minor disruption to the system layout.

21. Insulation material shall not contain chemicals that may react with the heater material and cause corrosion.

22. Insulation thickness is determined by the allowable heat loss from the traced equipment. Manufacturers of electric heat tracing systems shall supply tables showing the heat loss at various temperature differences.

23. The temperature control of electric tracing shall be kept as simple as possible. The sensing probes shall be selected with due regard to the maximum operating temperature. Controllers shall be one of the following types:

    a) Thermostat: The set point shall be the maintained temperature indicated on the electrical data sheets. Contacts shall be arranged to close on falling temperature. Thermostats for piping and instrument tubing installation shall be of the capillary tube type with switch enclosures suitable for the area classification. Where the heater current exceeds the rating of the thermostat contacts, the thermostat shall be used as a pilot device for a magnetic contactor rated to control the heater

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current. The thermostats shall be located where they will be easily accessible for maintenance.

b) Solid state thermistor: Consists of a temperature sensing probe with a thermistor and a solid state relay. Each solid state relay shall be capable of being adjusted over a temperature range by means of a potentiometer. Thermistors for piping and instrument tubing installations shall be bead-type probes or equal. Resistance tolerances shall be 5 percent maximum.

c) High-temperature limiters: Shall be used as a backup for the temperature controller in cases where overheating the line must be prevented, such as on caustic, amine, acids, etc. Switch action shall cause heating shutdown and shall actuate an alarm.

24. Power supply requirements are as follows:

a) Heat tracing systems shall be supplied from their own distribution transformers. Preferred heater cable voltages shall be 120, 208, 240 and 480 volts. In series resistance cables, voltages less than 120 volts may be used.

b) Transformers feeding heat tracing distribution centers shall be the compound filled, outdoor type, 480-120/208 volts, three phase or 480-120/208 volts, single phase. Such transformers shall be located near the distribution centers. Other transformer primary voltages and frequencies may be used where required to be consistent with local standards. The transformers shall have two $2\,^{1}/_{2}$ percent full-capacity taps above and two $2\,^{1}/_{2}$ percent full-capacity taps below normal rated primary voltage. Each transformer shall be provided with primary protection by means of a circuit breaker or a fused disconnect switch.

c) Transformers required to reduce the voltage from 120 volts to 48, 24 or 12 volts shall be the compound filled, outdoor type, located where the heater receives its source of supply. Transformer primary protection shall be provided by means of a locally mounted thermal overload switch with enclosure suitable for the area classification.

25. Self-limiting heating cables installed in a classified or hazardous area shall have an overall braid or sheath having a low ground path resistance, such as tinned copper, with a protective outer jacket.

5.4. Circuit Schedules and Description

The contractor shall be required to obtain Mobil approval for circuit schedules in tabular form. Information in the schedules shall include, but not be limited to:

1. Cable type.
2. Number of cables.
3. Reference drawing.
4. Number.
5. Voltage.

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6. Current.
7. Watts per unit length (metric or customary).
8. Thermostat temperature setting.
9. Cable lengths.
10. Resistance.
11. Area classification.
12. Traced line size.
13. Normal line temperature.
14. Insulation thickness.
15. Minimum and maximum acceptable fluid temperature.

5.5. Drawings

Standard drawings shall be furnished by the contractor to show the following:

1. Straight single tracer runs.
2. Dual and triple tracer installations.
3. Traced valve bodies and bonnets.
4. Traced flanges and unions.
5. Traced pump casings and vessel drawoff pots.
6. Traced takeoff and block valves for instruments.
7. Traced instruments–all types on the project.
8. Typical thermostat installation.
9. Typical panelboard details.
10. Typical monitoring details.

5.6. Specifications

Mobil approval of detail specifications is required on the following:

1. Cable lengths.
2. Junctions and junction boxes.
3. Factory and field testing.
4. Attachment requirements.

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5. Installation methods.
6. Transformer location, type and space requirements.
7. Thermostat and relay types.
8. Records of testing.
9. Monitoring systems.

6. Hot Oil Systems Equipment

Hot oil systems circulate heat transfer oils at temperatures up to 316°C (600°F) through a closed system to supply heat to process equipment or piping.

6.1. Expansion Tank

1. The dual purpose of the expansion tank is to permit expansion of the oil as it is heated without exposing hot oil to air and to function as an oil seal. The temperature of the oil in the tank shall not be over 54°C (130°F). The tank and connecting pipe shall not be insulated.
2. The expansion tank shall be at an elevation above all outlets and heater tubes and shall be connected to the pump suction or return line. The tank shall have the following items:
   a) Vent to allow air to escape. If oil is heated above its flashpoint, the vent shall be of the pressure/vacuum type.
   b) Drain for moisture.
   c) Fill line and overflow line.
   d) Level indicator.
   e) Temperature indicator.
   f) Low level alarm.
3. The expansion tank shall be sized to be one-quarter full when the oil in the system is cold and over three-quarters full when the oil is hot. The amount of expansion will vary with different oils. For Mobiltherm, the expansion can be calculated from this formula:

   Percent increase in volume = 0.063 x rise in temperature, °C

   or

   Percent increase in volume = 0.035 x rise in temperature, °F

   For other oils/fluids, use appropriate factors.

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6.2. Pumps

Either centrifugal or positive displacement pumps can be used for circulating the hot oil. Pump capacity shall be sufficient to circulate the oil at a rate that will provide the heat required by the users, including the heat losses, with a temperature drop of 11°C to 28°C (20°F to 50° F) between the incoming and out-going oil flow. The suction of the pumps shall be under positive pressure to prevent the influx of air and the pump shall discharge to the heater.

6.3. Heater

The oil can be heated by steam, electric or fired heaters. Fired heaters are most commonly used and shall be designed specifically for this service. This MEP is not intended to provide details of heater design, but the following shall pertain:

1. The oil flow through the tubes shall be positive and not depend on convention currents.
2. The heat-storage capacity of the combustion chamber shall be low so that the oil is not over-heated if a pump fails.
3. Snuffing steam, if available, shall be piped to the heater.

6.4. Controls

Heat transfer systems shall be protected with controls and safety devices against the following contingencies:

1. Excessive temperature.
2. Flow failure.
3. Excessive pressure.
4. Heater flame failure.

Fired heaters shall be equipped with the standard safety controls specified in MP 33-P-01.

6.5. Materials

Materials of construction shall be as follows:

1. Carbon steel shall be used for the entire piping system. (Piping shall conform to MP 16-P-01 and MP 16-P-31A.) Copper and copper alloys shall not be used.
2. Packings and gaskets shall be of material resistant to oils, as follows:
   a) For temperature below 93°C (200°F), Buna N is satisfactory for seals and O-rings.

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b) For temperature to 121°C (250°F), Viton seals can be used.

c) For temperatures 121°C to 204°C (250°F to 400°F), fluorinated resins such as Teflon shall be used.

d) For temperatures over 204°C (400°F), high-temperature nonasbestos packing or metallic seals shall be used.

3. Insulation of hot oil systems shall be in accordance with MP 34-P-10. However, in areas where leaks are likely to occur, a nonabsorbent insulation such as cellular glass shall be used. Leakage of hot oil or product onto hot oil lines can soak into the insulation and become a fire hazard. The insulation shall be metal jacketed.

6.6. Heat Transfer Fluid

Heat transfer fluids such as Mobiltherm shall:

1. Resist deterioration from oxidation and cracking at the operating temperature.
2. Possess good heat transfer characteristics.
3. Have low vapor pressure at operating temperature.
4. Have low viscosity.
5. Protect metals against corrosion.
6. Be available at reasonable cost.

6.7. Tracers

Tracers for hot oil systems shall be Schedule 40, ASTM A53 or ASTM A106, Grade B seamless carbon steel pipe. Refer to Table 1 for allowable working pressures.

Carbon steel or stainless steel tubing may be used for tracing irregular piping and equipment. Copper tubing shall not be used. The tracers shall be banded to the pipe at 600 mm (24 in) intervals to maximize physical contact between the pipe and tracer.

6.8. Safety

When heat transfer oil is heated above its flash point, extreme care shall be taken to prevent leaks anywhere in the system.

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Instrumentation Project Basics

EPT 05-T-01

October 1992 Draft

Scope

This Engineering Practice Tutorial (EPT) outlines instrument philosophy, economic selection and the basic steps necessary for planning a successful instrument installation for onshore and offshore production and processing. Additional tutorials (EPT 05-T-02, EPT 05-T-03, EPT 05-T-04, EPT 05-T-05, EPT 05-T-06, EPT 05-T-07, EPT 05-T-08, EPT 05-T-09,EPT 05-T-10, EPT 05-T-11 and EPT 05-T-12) provide more detailed information on specific instrumentation devices and systems.

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Table of Contents

Scope **1**

1. References **4**

1.1. MEPS–Mobil Engineering Practices 4

1.2. Mobil Tutorials 4

1.3. API–American Petroleum Institute 4

1.4. ASME–American Society of Mechanical Engineers 5

1.5. GPSA–Gas Processors Suppliers Association 5

1.6. ISA–Instrument Society of America 5

1.7. Additional References 5

2. General **6**

3. Project Organization **6**

3.1. Basic Steps 6

3.2. Project Definition 6

3.3. Instrument & Control Philosophy 6

3.4. Safety Considerations 7

3.5. Economics 7

4. General Requirements **7**

4.1. PFDs and P&IDs 7

4.2. Instrument Air/Power 7

4.3. Instrument Piping 8

4.4. Instrument Index 8

5. Instrument Specifications and Drawings **9**

5.1. Data Sheets 9

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5.2. Loop Diagrams....10
5.3. Location Plans....10
5.4. Installation Details....10
5.5. Interconnecting and Detailed Construction Drawings....10
5.6. Logic Diagrams....10
5.7. Cause and Effect Charts....15
5.8. SAFE Charts....16
Appendix A: Nomenclature....17
Appendix B: Project Instrument Requirements....21

1. References

The following publications form a part of this EPT. Unless otherwise specified herein, use the latest edition.

1.1. MEPS–Mobil Engineering Practices

MP 00-P-02	CADD Requirements - Drawings and System
MP 32-P-01	General Requirements for Instrumentation

1.2. Mobil Tutorials

EPT 04-T-02	Flare and Vent Systems
EPT 05-T-02	Controllers and Control Theory
EPT 05-T-03	Flow Measurement and Control
EPT 05-T-04	Level Measurement and Control
EPT 05-T-05	Temperature Measurement and Control
EPT 05-T-06	Process Measurement and Control
EPT 05-T-07	Control Valves
EPT 05-T-08	Relief Valves and Rupture Disks
EPT 05-T-09	Distributed Control Systems (DCS)
EPT 05-T-10	Programmable Logic Controllers (PLC)
EPT 05-T-11	Safety Shutdown Systems
EPT 05-T-12	Wellhead Control Panels

1.3. API–American Petroleum Institute

API RP 14C	Recommended Practice for Analysis, Design, Installation, and Testing of Basic Surface Safety Systems for Offshore Production Platforms Fifth Edition; Errata - 1994
API RP 520 PT I	Sizing, Selection, and Installation of Pressure-Relieving Devices in Refineries Part I - Sizing and Selection Sixth Edition; Errata - 1994
API RP 520 PT II	Sizing, Selection, and Installation of Pressure-Relieving Devices in

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	Refineries Part II - Installation Fourth Edition

1.4. ASME–American Society of Mechanical Engineers

ASME SEC VIII DIVISION 1	BPVC SECTION VIII Rules for Construction of Pressure Vessels DIVISION 1 Non-Interfiled (Boiler and Pressure Vessel Codes)

1.5. GPSA–Gas Processors Suppliers Association

EDB-I	Engineering Data Book - Volume I, 1987
EDB-II	Engineering Data Book - Volume II, 1987

1.6. ISA–Instrument Society of America

ISA RP7.7	Producing Quality Instrument Air Superseded by: S7.0.01: 1996
ISA S5.1	Instrumentation Symbols and Identification R(1992)
ISA S5.2	Binary Logic Diagrams for Process Operations R(1992)
ISA S5.3	Graphic Symbols for Distributed Control/ Shared Display Instrumentation, Logic and Computer Systems
ISA S5.4	Instrument Loop Diagrams
ISA S12.12	Nonincendive Electrical Equipment for Use in Class I and II, Division 2 and Class III, Divisions 1 and 2 Hazardous (Classified) Locations
ISA S20	Specification Forms for Process Measurement and Control Instruments, Primary Elements and Control Valves

1.7. Additional References

Chilton: Instruments Engineer's Handbook (2 Volumes): Process Measurement and Process Control
Crane, "Flow of Fluids Through Valves, Fittings & Pipes," Technical Paper No 410

2. General

Instrument philosophy, economic selection and the basic steps necessary for planning a successful instrument installation for onshore and offshore production and processing shall be in accordance with requirements of this MEP, unless superceded by more stringent local regulations.

3. Project Organization

3.1. Basic Steps

Instrumentation includes not only the selection and sizing of sensing and control devices, but also the process control system. Thus instrumentation comprises a project within the overall facility design project. The instrument project can be defined in five basic steps:

1. Project Definition
2. Instrument Control Philosophy
3. General Requirements
4. The Instrument Index
5. Instrument Specifications and Drawings

3.2. Project Definition

Project definition is the process of determining not only the types of instrument devices to be employed but also establishing the process control requirements. This includes both the requirements of process system components (separation, glycol systems, etc.) and the requirements of operating personnel. To this end, a sample project instrument requirement checklist is presented in Appendix B.

3.3. Instrument & Control Philosophy

An instrument and control philosophy is a decision not only regarding the particular instrument to be used but also how the facility shall be operated. A philosophy is determined by following the project instrument requirements checklist in Appendix B and applying safety and economic considerations.

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3.4. Safety Considerations

Safety considerations primarily include protection of life, the environment and capital investment. Control systems employ some form of fail-safe mode in the event of component/system failure or detected catastrophic event (e.g., fire, gas detection, etc.). Refer to the tutorial EPT 05-T-11 on Safety Shutdown Systems for more details.

3.5. Economics

Cost control is of primary importance and is second only to safety and system compatibility. Control system costs vary with type and complexity. For example, a typical pneumatic control panel for a glycol system ranges near $45,000 U.S., while the same panel with electronics might cost $35,000. But additional cable requirements may bring the cost of an electronic system much closer to that of a pneumatic system. The average cost of a PLC system is approximately $1100 per loop, and that of a DCS is approximately $1800.

4. General Requirements

4.1. PFDs and P&IDs

The primary sources for data used in sizing and selecting relief and control valves and the design of an instrumentation system are the facility PFDs and P&IDs. It is the instrument engineer's responsibility to use this data for the sizing and selection of all instruments. Normally, the instrument engineer is involved in the development of the facility P&IDs. In the course of designing the instrumentation system, it may be necessary to modify the P&IDs or seek additional information on process variables, expected range of conditions that may not be clearly identified on the PFDs, etc.

The specific type of control, whether remote or local, pneumatic or electronic, along with its relationship to the overall control system, shall be indicated for each system/unit on each P&ID. The way the various types of control functions are shown on the P&IDs is described on the project P&ID legend drawing.

4.2. Instrument Air/Power

The instrument air supply shall be from a clean and dry source of air between 550 and 860 kPa (80 and 125 psig). Generally, the minimum air pressure for valve actuation is 550 kPa (80 psig), while the maximum for control loops is 205 kPa (30 psig), although they are normally operated at 140 kPa (20 psig). Normal pressure for sensing elements is 20 to 100 kPa (3 to 15 psig). A positioner or relay/solenoid valve is commonly used to interface

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the control circuit to the valve actuator circuit. Refer to ISA RP7.7 for more details on the instrument air system design.

Electronic instrument systems generally operate at standard DC and AC voltages. Analog sensing elements normally operate at 24 VDC, producing a 4 to 20 mA signal, while contact device switches can operate at 24 VDC, 120 VAC or 240 VAC. Electronic devices used in production and processing facilities are normally required to have an electrical classification for class I Division 1 or Class I division 2, or be intrinsically safe. Refer to ISA S12.12 for more details.

4.3. Instrument Piping

Instrument piping, which includes all valves, headers, manifolds, and tubing, shall be appropriate for the service intended and installed in a safe and secure manner. Refer to MP 32-P-19 for specific requirements.

4.4. Instrument Index

The instrument index is normally created as instrument tags are developed, since the index is a primary design control document. It contains the complete listing of all instruments and their relationships to the process control and shutdown system. Where microprocessor, loop controllers, PLCs, or DCS systems are employed, the database will include each I/O and its respective address and type. The index is used during the design phase as a progress control device. During construction, the index serves as a specification and procurement control document. When the system calibration and checkout are performed during installation and startup, the index is updated with these records. After project completion, this document is maintained to provide an up-to-date facility instrument record. Typical data fields in the index are:

1. Revision and date
2. Tag prefix
3. Tag function identifier
4. Tag number
5. Tag suffix
6. Manufacturer
7. Model number
8. Scale range
9. Calibrated range or set point
10. Process line or equipment (where the instrument is located)
11. Data sheet specification number

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12. P&ID drawing number
13. Location plan drawing number
14. Loop drawing number
15. Pneumatic installation detail drawing number
16. Electronic installation detail drawing number
17. DCS address
18. I/O (Input/Output) card
19. I/O slot
20. I/O address
21. DC discrete input
22. DC discrete output
23. AC discrete input
24. AC discrete output
25. Analog input
26. Analog output
27. High speed counter input
28. Low speed counter input
29. Notes

5. Instrument Specifications and Drawings

5.1. Data Sheets

Data sheets comprise the detailed specifications for each instrument item and contain all data are required for procurement of instruments that are compatible with the process and project environment. This includes required materials of construction. Standard fill-in-the-blank data sheets are provided in the MEPS listed in Section 1 of this EPT. Virtually all instrument manufacturers and most engineering contractors have computer-based instrument data sheets that are generally patterned after ISA S20. The supplying vendor shall be required to provide a confirming data sheet that includes calculation results for each control and relief valve.

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5.2. Loop Diagrams

The loop diagram provides control data and information about a particular process variable or controlled element (e.g., pressure, temperature, flow, etc.). Normally, a single 11 in by 17 in drawing is developed for each controlled variable. Each loop contains pertinent range, calibration and set point data. Typical loop diagrams are detailed in ISA S5.4. Where DCS, PLC or microprocessor controllers are employed, these loops shall include field marshalling panels and I/O racks, with redundancies, to completely define each loop.

5.3. Location Plans

Instrument location plan drawings are prepared to provide location and identification of all instruments during the construction phase and to assist in personnel training and operations. These drawings normally document as-built conditions and shall be maintained thereafter.

5.4. Installation Details

Instrument installation details are typically 280 mm by 430 mm (11 in by 17 in) detailed construction drawings that contain all physical and technical data regarding each instrument, including how and where it is to be installed. These drawings provide the primary source of procurement data required for instrument installation.

5.5. Interconnecting and Detailed Construction Drawings

Interconnecting and detailed construction drawings depict the interconnecting cable, conduits, or tubing between operating units, control panels, field marshalling panels, etc. These drawings provide information required to install instrumentation systems accurately and safely and to specify additional material requirements not listed on the installation detail drawings.

5.6. Logic Diagrams

Logic diagrams are flow charts of the facility's process control, shutdown and alarm systems. Figure 1 shows a simple P&ID of a vessel with high and low level control of an outlet valve. The high level switch, or level switch high (LSH-12101), is a normally closed switch. Its contacts open when a high level is detected. The low-level switch LSL-12101 is a normally open switch. Its contacts close when level is equal to or above the set point. The diamond with "I1" indicates the following logic function: when the vessel reaches the high level point, the switch opens, causing valve LV-12101 to open. The valve remains open until the level falls below the low level switch set point. Panel mounted visual indication (LAH-12101 and LAL-12101) is added as an operational aid

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only. The devices indicated in this example are shown to be electronic instruments. When pneumatic devices are use, the only representation change would be to show air lines in place of electronic pathways.

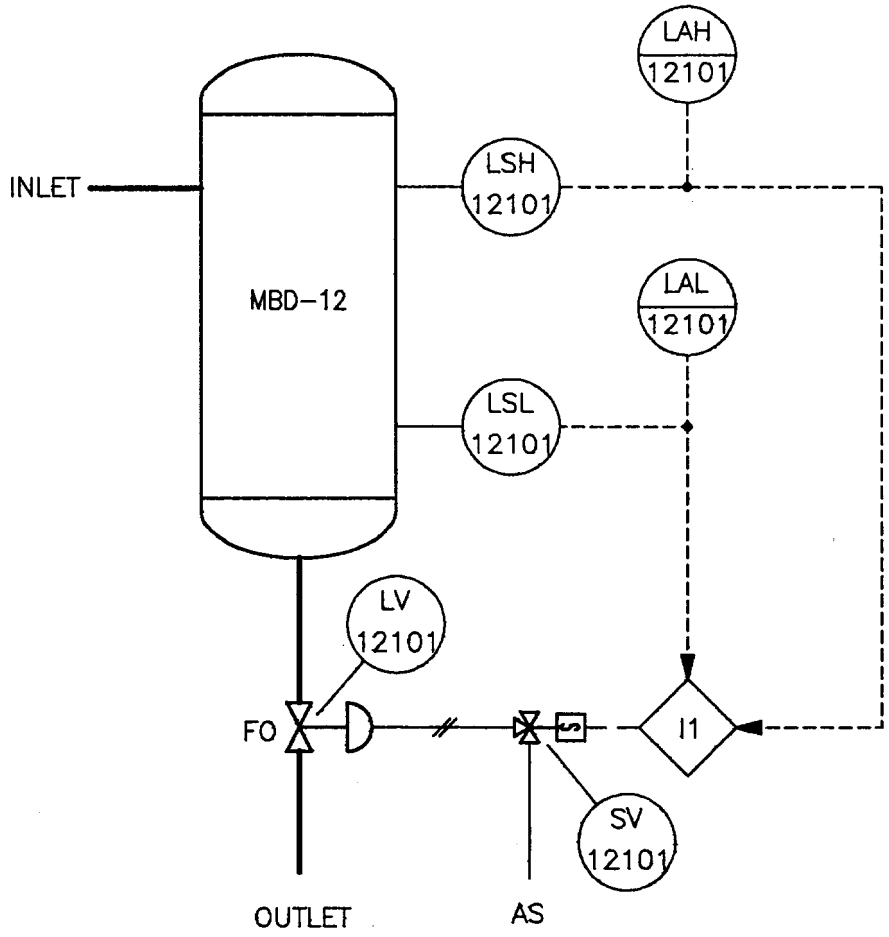

Figure 1: Simple P&ID of a Vessel

5.6.1. Logic Diagram

Figure 2 is the logic diagram for the above depicted control circuit. If a high level exists (LSH-12101=0), SV-12101 is turned on (SV-12101-1) and a locking signal is returned to the low level "AND" gate, locking SV-12101 ON until low level (LSL-12101=0) is reached. LSH-12101 will return to a value of 1 when the level falls below high set point.

Where microprocessor-based controllers, PLCs or DCS systems are used, these logic diagrams also include functions and I/O addressing to aid in system programming. Refer to ISA S5.1, ISA S5.2 and ISA S5.3 for specific details on logic diagrams and symbol definitions.

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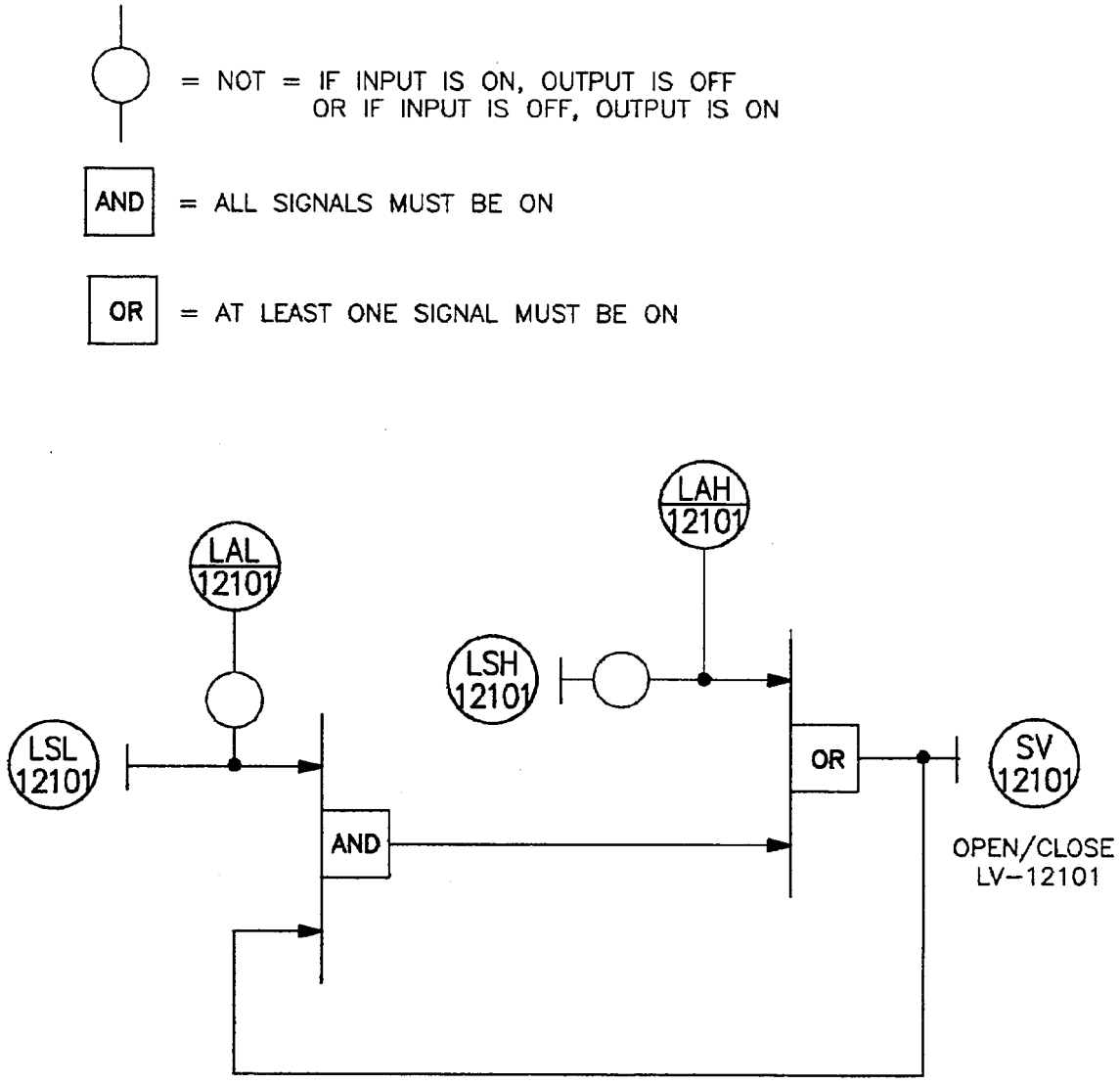

Figure 2: Electrical Ladder Diagram Schematic–Logic Diagram

5.6.2. Circuit Diagram

Figure 3 is an electrical "ladder diagram" schematic of the circuit required to perform the task defined for Figure 1. Note: all relay contacts are shown in the de-energized position. This diagram shows LSH-12101 closed, energizing relay R1. LSL-12101 is shown open, thus relay R2 is de-energized and the low level alarm light is ON. Relay R3 is de-energized, thus de-energizing solenoid valve SV-12101 and closing LV-12101. As the level increases, LSL-12101 closes and energizes R2; everything remains the same except that the LAL indicator is turned OFF. When R1 is de-energized by the rising level, its contact will energize R3, R3 will lock itself and SV-12101 in ON through the normally open contacts of R2. A falling level will

close LSH-12101 and energize R1. When R2 is de-energized (low level), R3 will again de-energize. When R3 is de-energized, SV-12101 is de-energized, closing LV-12101 by supplying air to the valve actuator. (Note that when both high and low level lights are on, a switch malfunction has occurred.)

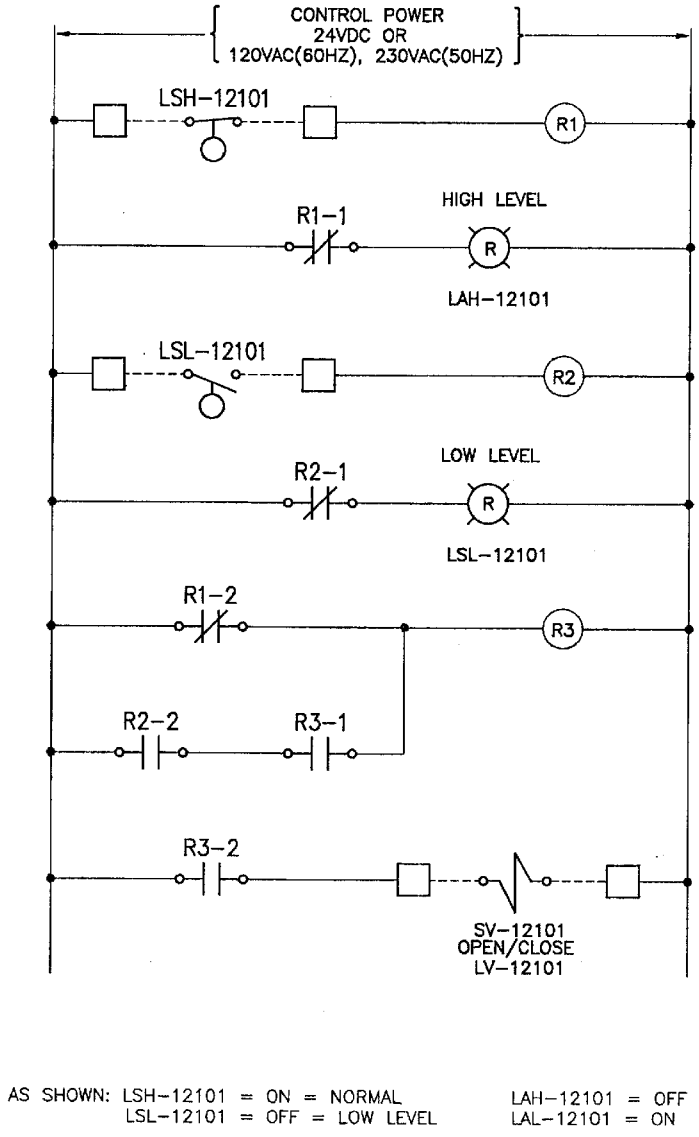

Figure 3: Electrical Ladder Diagram Schematic

5.6.3. Pneumatic Form

Figure 4 shows the same circuit in pneumatic form. R1, R2, R3 and SV-12101 are pilot-operated three-way valves. The port with the circle is blocked when the pilot is de-energized, and the unmarked port is vented through the port with the line. When sufficient vessel level is present, a positive pressure shall be applied to the pilot of R2, thus energizing it.

Nothing will happen until a loss of pressure through R3 from LSL-12101 causes R1 to reset and place control air to the pilot of R3, locking out the LSH-12101 signal before it can reset. Energizing SV-12101 removes the air supply to LV-12101, thus opening the valve. The valve shall remain open until low level de-energizes R2, de-energizing both R3 and SV-12101. It shall be noted that pneumatic control systems are seldom used today.

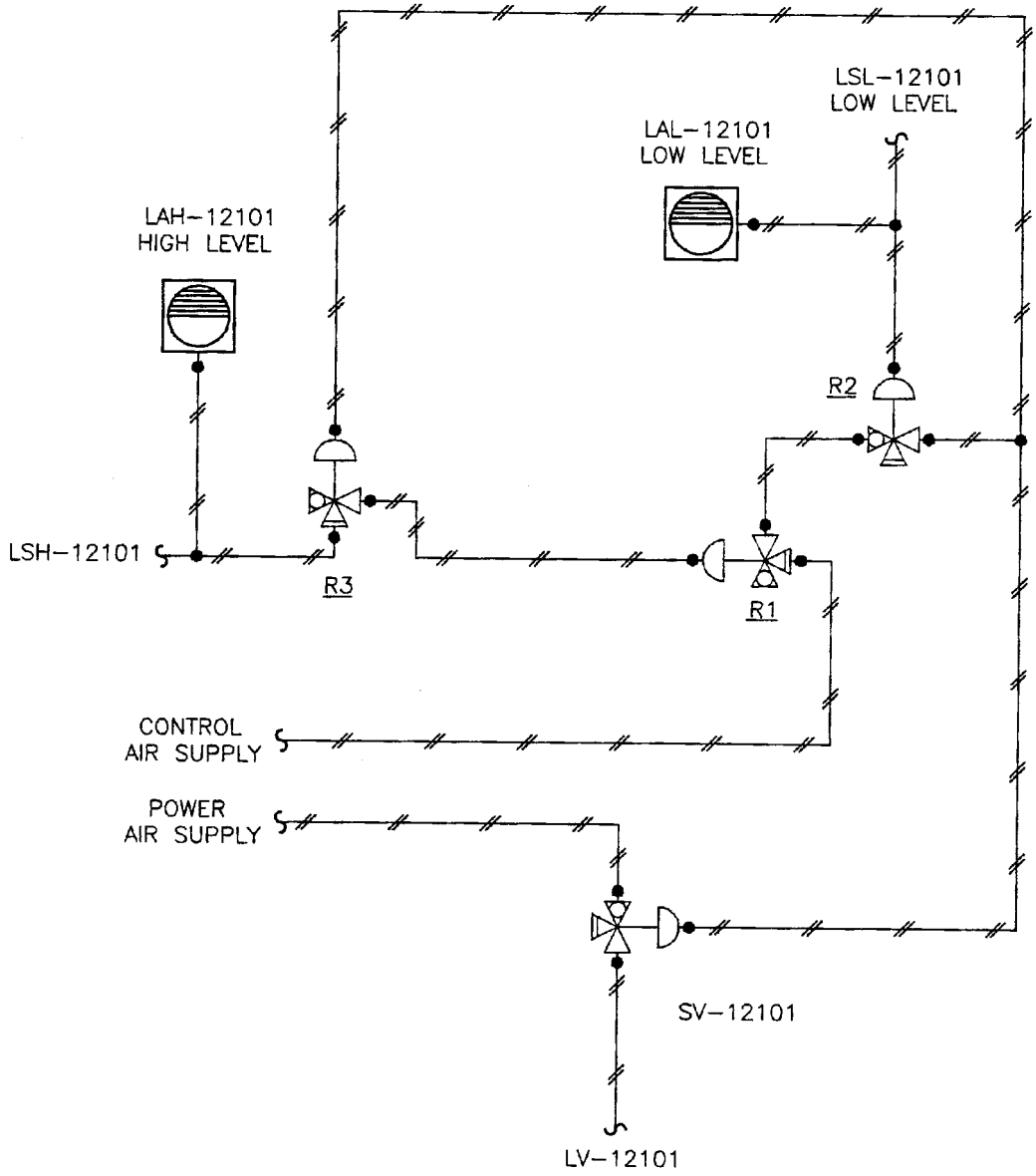

Figure 4: Electrical Ladder Diagram Schematic–Pneumatic Form

5.7. Cause and Effect Charts

Cause and effect charts are cross-referenced charts depicting the results or actions resulting from the activation of a process function (e.g., Pressure Shutdown High, Pressure Shutdown Low, Level Shutdown High, Level Shutdown Low, etc.). These charts are the basic description of the control, shutdown and alarm system. Where

microprocessor-based controllers, PLCs or DCS systems are used, these charts aid in system programming.

5.8. SAFE Charts

Safety Analysis Function Evaluation (SAFE) charts are cause- and-effect-type cross reference charts depicting basic surface safety systems for offshore production platforms, as defined by API RP 14C. These charts are required for offshore facilities in the U.S. and are a guide for onshore and international offshore facilities.

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Appendix A: Nomenclature

PFD	Process Flow Diagrams contain design data for a particular facility. This data includes planned operating conditions, alternate operating modes, and design conditions (minimums and maximums). This data is the basic controlling element for the design of a production or processing facility. Refer to MP 00-P-02, Flow diagrams - General Requirements, for details.
P&ID	Process & Instrument Diagrams, sometimes called Mechanical Flow Diagrams, are the schematic representation of the production or processing facility and, as a minimum, include design and operating conditions, system set points, and basic control philosophy. Refer to MP 00-P-02, Flow Diagrams - General Requirements, for details.
Microprocessor-Based Controllers	In general, these systems are programmable multi-loop controllers with data storage, control strategy and communications capabilities, capable of being incorporated into various types of control system networks or stand-alone operations. ISA S5.3 has some basic information relating to these computerized units. Refer to the tutorial EPT 05-T-02 on Controllers and Control Theory for details.
Programmable Logic Controller (PLC)	The programmable logic controller, or simply programmable controller, is a unified control system designed to provide both digital and continuous (analog) logic control. A PLC can function on its own or as a part of a DCS. Since PLCs operate in a digital format, they can communicate with computers relatively simply. Refer to the tutorial EPT 05-T-10 on Programmable Logic Controllers for details.
Distributed Control System (DCS)	Distributed control systems (DCS) are a form of industrial process control. Equipment making a distributed control system can be separated into two basic sections: (1) the equipment used by the operator to monitor process conditions and to manipulate the controls located in a central control room, and (2) the controlling portion of the system, which is sometimes located at various points throughout the process area as well as in the central control room; this portion performs the two basic functions of measurement and generation of output signals to change/control process conditions at each location. These are the components that connect directly to the field/end devices. Data (instructions and information) is communicated between the central location and the distributed controller locations by means of an electronic transmission system. The communications path may be either a cable from each remote location to the central unit or a cable data highway interfacing all the locations. The remotely located controllers may be the components of the DCS system's manufacturer or a mix of PLCs and/or microprocessor based units. Refer to the tutorial EPT 05-T-09 on Distributed Control System for details.
I/O (Input/Output)	I/O racks are the cabinets that house the signal conditioning interface

Racks	boards that connect the field device to the PLC or DCS processors. Refer to the tutorial EPT 05-T-10 on Programmable Logic Controllers and the tutorial EPT 05-T-09 on Distributed Control System for detailed information.
Redundant Modules	Redundant modules are automatic backup I/O and/or processor cards. These are a standard feature in DCS, multi-loop controllers and microprocessor-based ESD Systems and are available in PLC systems. Refer to the tutorial EPT 05-T-09 on Distributed Control System, the tutorial EPT 05-T-02 on Controllers and Control Theory, and the tutorial EPT 05-T-11 on Safety Shutdown Systems for detailed information.
Field Marshalling Panels	Field marshalling panels are the cabinets that house terminal blocks and power supplies used in the interface of field instruments/devices to electronic processor based systems. Refer to the tutorial EPT 05-T-10 on Programmable Logic Controllers and the tutorial EPT 05-T-09 on DCS for more information.
Unit	A production/processing unit is a portion of a facility (e.g., separator, glycol system, etc.), and may be either a single component or a system.
Train	A production/processing train refers to a stand-alone operating system that is incorporated with other systems to form the total facility. Trains are usually identical systems in which an upset in one system does not affect the other(s).
ROM	ROM is Read-Only Memory. Once the manufacturer burns the data into the chip, it cannot be changed.
PROM	PROM is Programmable Read-Only Memory. This type of chip allows the user to burn in the data; however, this action can be done only once, and it requires a special programming device.
EPROM	EPROM is Erasable Programmable Read-Only Memory. This type of chip can be erased many times by exposure to ultraviolet light. However, the chip shall be removed from the system for this operation, and a special programming device is required to re-program the chip.
EEPROM	EEPROM is Electrically Erasable Programmable Read-Only Memory. As with other types of ROMs, data storage is non-volatile, but this type of chip can be re-programmed without removing it from the system and without special PROM programming devices.
RAM	RAM is Random Access Memory. This type of chip is read-and-write-volatile memory, i.e., the data is lost when power is removed and must be rewritten to the chip after the power is applied.
CMOS	CMOS is Complementary Metal Oxide Semiconductor memory. It is electrically re-programmable without special devices. It is a volatile storage that requires a very small amount of power.
Boolean Algebra	Boolean algebra refers to the algebraic mathematics used to manipulate logic expressions. Boolean expressions generally convey relationships involving “and," “or” and “not." As an example of applying Boolean logic to a ladder diagram, refer to Figures 2 and 4, which depict a series of contacts controlling a solenoid. In the diagram, if either R1 is de-

	energized or R2 and R3 are energized, solenoid SV shall be energized. Expressing this in Boolean logic format: $\frac{1}{R1} + (R2 * R3) = SV$ Where: $\text{Not } A = \frac{1}{A}$ A and B = A*B A or B = A +B
Hand-Held Terminal	A hand-held terminal is a PLC programming device specifically designed for a particular manufacturer's PLC. These devices are commonly used to program small PLC units and usually use a Boolean format in programming.
Configuration Software	Configuration software refers to the manufacturer's PLC programming software. This software usually includes instructions and options for defining the PLC's hardware architecture, as well as for control program development and documentation.
I/O Bus	The I/O bus is the system hardware and software that houses and controls the data input and output (I/O). Control is through a mechanism called multiplexing, which is the interfacing of the I/O signals with the Central Processing Unit (CPU) data logic and which allows the CPU to select particular I/O signals for processing.
Smart I/O	Smart or intelligent I/O modules provide processing functions such as American Gas Association (AGA) flow calculations, PID control, computing, data storage and retrieval, and communications. These functions are accomplished without directly involving the central processing unit. In the application of these modules, multi-tasking is used to achieve maximum speed in the control functions carried out by the CPU. Some systems employ special multi-tasking CPUs to accomplish this.
Watch-Dog Timer	A watch-dog timer is a timing device that generates a signal to advise the conclusion of an event. The CPU watch-dog timer is used to check that all functions are complete within the scheduled scan time; it indicates a CPU failure if any function is not complete. Watchdog timers can also be used in a control program to control or regulate the operation of tasks or sub routines.
RTU	A Remote Terminal Unit is a control and data acquisition device. A PLC can function as an RTU.
PID	Proportional Integral Derivative control is the most complex of the

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	conventional control modes and is commonly referred to as three-mode control. Its most common application is in temperature control. However, the acronym PID is often used simply to indicate that some form of modulating control is required or is being used.
Multiplexer	A multiplexer enables multiple signals to share common equipment on a time-share basis.
Process Sensing Devices	Process sensing devices are the elements used to provide system conditions of pressure, temperature, etc., to the operator, either in the form of direct indications or as signals to the controlling system or device(s).
Data Manipulation Devices	Data manipulation and indication devices are the elements used to provide the operator with real-time, historical, trending, etc., status of the facility. These devices may be control panels, processors, and/or computers and are normally located in a central control room.
Control Devices	Control devices are the elements that make up individual control loops or systems. This term includes pneumatic and electronic loop controllers, microprocessor-based controllers, DCS, and PLC systems as well as the controlled devices (valves, etc.) themselves.
Pressure Relief Devices	Pressure relief devices are the thermal relief valves, pressure safety valves, etc. that are employed to protect the facilities under abnormal conditions (e.g., control system failure). The application of these devices is controlled by industry codes (API RP 520 I, ASME SEC VIII, etc). See the tutorial EPT 04-T-02 on Relief Valves and Rupture Disks for more information.

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Appendix B: Project Instrument Requirements

The primary purpose of this Appendix is to ascertain the type and configuration of the various instrument systems required. A secondary purpose is to solicit specific vendors and specific instrument data.

The development of the instrumentation philosophy, design and hardware at the beginning of a project will save time and reduce cost.

General Requirements				
A. Regulatory Requirements for Safety Systems				
	1.	MMS		
	2.	API RP 14C		
	3.	Other		
	Comments			
B. Type of Control System				
	1.	Pneumatic		
	2.	Electric		
	3.	PLC		
	4.	DCS		
	Comments			

General Requirements								
C. Instrument Supply System								
	1.	Air						
	2.	Gas						
	3.	Supply Header Pressure, kPa (psig)						
	Comments							
D. Code Requirements								
	1.	NACE						
	2.	Other						
E. Alarm Types and Locations								
	1.	Alarm on Shutdown only						
	2.	Pre-Alarm Selected Points,			, Point Locations			
	3.	All Alarms Local						
	4.	Alarms Local and Off-Site						
	Comments							
	5.	Telemetry						

Wellheads								
A. Design Data								
	1.	Number of Wells		Gas		Oil		
	2.	Shut-In Pressure, Gas						
		Oil						
	3.	Waterflood, Yes or No			Pressure			
	4.	Gas Lift, Yes or No			Pressure			
	Comments							
B. Configuration								
	1.	Down Hole:						
		a.	Ball Valve					
		b.	Velocity Valve					
		c.	None					
	2.	Master Valve			Automated			
	3.	Wing Valve			Automated			
	4.	Chokes, Fixed			Adjustable			
	5.	Second Choke or Tee 10 pipe diameters from first choke						
	6.	Pressure Rate Flowline						
	Comments							
C. Type of Valve Actuators								
	1.	Hydraulic, Location						
	2.	Pneumatic, Location						
D. Miscellaneous								
	1.	Local Reset Relay at Master & Wing Valves						
	2.	Fusible Plugs to be part of Valve Tubing at Wellhead						
	3.	Wellhead Remote from Panel Location						

Wellheads	
	Comments

Shutdown Valves								
A. Type, Size and Actuator								
	1.	Ball						
	2.	Gate						
	3.	Butterfly						
	4.	Other						
B. Configurations								
	1.	Bypasses around Valves			, Locations			
	2.	Local Reset Relays			, Locations			
	3.	Vents Tubed to Prevent Entry of Corrosive Atmosphere						
	4.	Inside of Piston & Diaphragm Housings Coated to Prevent Corrosion						
C. Preferred Manufacturers								
	1.	Ball Valves						
		a.	WKM					
		b.	Orbit					
		c.	AEV (American Energy Valve)					
		d.	KITZ					
		e.	Others					
	2.	Gate Valves						
		a.	Axelson					
		b.	WKM					
		c.	Others					
	3.	Butterfly Valves						
		a.	Fisher					
		b.	Masoneilan Camflex					

Shutdown Valves								
		c.	Posiseal					
		d.	Others					
	4.	Piston Actuators						
		a.	Bettis					
		b.	Rotork					
		c.	Others					
D. All Valves Fire Safe								

Control Valves								
A. Gas Service								
	1.	For pressure control use Yoke Mounted:						
		a.	Yoke Mounted Blind Controller					
		b.	Yoke Mounted Indicating Controller					
		c.	Remote Mount Blind Controller					
			Locations					
		d.	Remote Mount Indicating Controller					
			Locations					
	2.	Vent Valves Fail Open or Closed						
			Locations					
	3.	Are Butterfly Valves Acceptable?						
			Locations					
B. Liquid Service								
	1.	Angle body in 1000 psi DP and up service						
	2.	Valve with choke in 1000 psi DP and up service						
	3.	Other						
C. Miscellaneous								
	1.	Bypasses around Valves				Locations		
	2.	Bleed rings for taking valve out of line						
D. Preferred Manufacturers								
	1.	Fisher						
	2.	Norriseal						

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Control Valves								
	3.	Valtek						
	4.	Others						

Chokes								
A. Flowline								
	1.	Fixed			, Locations			
	2.	Adjustable			, Locations			
B. Process								
	1.	Fixed			, Locations			
	2.	Adjustable			, Locations			
C. Types								
	1.	Plug and Seat						
	2.	MOV (Rotating Disk)						
	3.	Closed Cage						
	4.	Other						
D. Preferred Manufacturers								
	1.	Thornhill Craver						
	2.	Willis						
	3.	Best						
	4.	Teledyne-Merla						

Chokes								
	5.	Other						

Relief Valves								
A. Configuration								
	1.	Dual Valves on Primary Process Vessels						
	2.	Relief Valve with Rupture Disc in parallel on Primary Process Vessels						
	3.	Relief Valve with Rupture Disc Located under Relief Valve						
	4.	Other						
B. Mounting								
	1.	Block Valves for Inlet and Outlet						
	2.	Block Inlet Only						
	3.	Check Valve Inlet Only						
	4.	Anderson Greenwood Safety Selector Valve on Inlet and Outlet						
	5.	Anderson Greenwood Safety Selector Valve on Inlet Only						
	6.	Other						
C. Types								
	1.	Conventional						
	2.	Snap Pilot						
	3.	Modulating, Non-Bleed Pilot						
	4.	Modulating, Bleed Pilot						
	Comments							
D. Miscellaneous								
	1.	Blowdown Around Relief Valves						
	2.	Remote Sense (For Piloting)						

Relief Valves							
	Locations						
E. Preferred Manufacturers							
	1.	Pilot					
		a.	Anderson Greenwood				
		b.	GPE				
		c.	Crosby				
		d.	Others				
	2.	Conventional					
		a.	Anderson Greenwood				
		b.	Crosby				
		c.	Consolidated				
		d.	Farris				
		e.	Others				
F. Comments							

Level Controls								
A. Configurations								
	1.	Internal Mounted			, Locations			
	2.	External Mounted			, Locations			
	3.	If External, Mounted on Bridles						
	4.	Block Valves on Bridles						
B. Mounting Type								
	1.	Vessel Mounts, Flanged			Screwed			
	2.	Bridle Mounts, Flanged			Screwed			
C. RTJ Flanges Start At:								
		ANSI 300						
		ANSI 600						
		ANSI 900						
D. Preferred Manufacturers								
	1.	Fisher						
	2.	Norriseal						
	3.	Magnetrol						
	4.	MSW						
	5.	Others						
E. Comments								

Measurement							
A. Gas							
	1.Primary Elements						
		a.	Orifice		, Locations		
		b.	Turbine Meters		, Locations		
		c.	Roots Meters		, Locations		
		d.	Other				
	2. Orifices						
		a.	Senior Fittings		, Locations		
		b.	Junior Fittings		, Locations		
		c.	Fabricated Meter Run		, Locations		
	3. Turbine Meters						
		a.	Battery Powered Local Readout				
		b.	Remote Readout				
		c.	RTU Input Only				
		d.	Other				
	4. Configuration						
		a.	With Prover Connections		, Locations		
	5. Preferred Manufacturers						
		a.	Turbine Meters				
			1.	Halliburton			
			2.	Hydril			
			3.	Daniel			
			4.	Other			
		b.	Orifice				
			1.	Daniel			
			2.	Superior			
			3.	Other			

Measurement								
B. Liquid								
	1. Primary Elements							
		a.	Positive Displacement					
		b.	Turbine Meter					
		c.	Orifice					
		d.	Other					
	2. Orifice							
		a.	Flanges			Location		
		b.	Fittings			Location		
	3. Turbine Meter							
		a.	Battery Powered Local Readout					
		b.	Remote Readout					
		c.	RTU Input Only					
		d.	Other					
	4. Configuration							
		a.	With Prover Connections			, Locations		
	5. Preferred Manufacturers							
		a.	Positive Displacement Meters					
			1.	ITT Barton (Floco)				
			2.	A.O. Smith				
			3.	Rockwell				
		b.	Turbine Meters					
			1.	Halliburton				
			2.	Hydril				
			3.	Daniel				
			4.	Other				
		c.	Orifices					

Measurement								
			1.	Daniel				
			2.	Superior				
			3.	Daniel				
			4.	Other				

Control Panels								
Pneumatic								
Electric								
A. Panels								
	1. Main							
		Configuration						
		a.	One central panel for shutdown and first out indication					
		b.	One central panel for first out indication and total shutdown logic, and remote panels for each piece of major equipment or system					
		c.	Other					
		Pressure Pilots						
		a.	Mounted in Panel					
		b.	Remote Mounted					
		Bypass Valves						
		a.	Bypass for each shutdown point plus circuit plus total panel bypass					
		b.	Bypass for each shutdown circuit only					
		c.	Total panel bypass only					
		d.	Auto reset					
	2. Well Head Panels							
		a.	Pressure Pilots Mounted in Panel					
		b.	Pressure Pilots Remote Mounted					
		c.	Hydraulic Pumps					
			1.	Haskell				
			2.	Other				
B. Panel Equipment								
	1. Fittings							

Control Panels								
		a.	Swagelok					
		b.	CPI Parker					
		c.	Gyrolok					
		d.	Cajon					
		e.	Flodar					
		f.	Other					
	2. Ball Valves							
		a.	Parker					
		b.	Whitey					
		c.	Lange					
		d.	Apollo					
		e.	Hoke					
		f.	Other					
	3. Interface Valves							
		a.	Sigma					
		b.	Haskell					
		c.	Pneu-Hydro					
		d.	Other					
	4. Logic Valves							
		a.	BWB					
		b.	Versa					
		c.	ISI					
		d.	Sigma					
		e.	Control Tronics					
		f.	Other					
	5. Filter Regulators							
		a.	Norgen					
		b.	Fisher					
		c.	GO					
		d.	Watts					
		e.	Other					
	6. Gauges							

Control Panels								
		a.	Hannie					
		b.	McDaniel					
		c.	Marsh					
		d.	Ashcroft					
		e.	Other					
	7. Pressure Sensors							
		a.	Axelson					
		b.	WKM					
		c.	Calcon					
		d.	AMOT					
		e.	Autoguard					
		f.	Fisher 4660					
		g.	Other					
	8. Needle Valves							
		a.	Anderson Greenwood					
		b.	HEV					
		c.	Dragon					
		d.	Whitey					
		e.	Sno-Trik					
		f.	Magnum Valve					
		g.	Other					
	9. Indicators							
		a.	AMOT					
		b.	BWB					
		c.	Control Tronics					
		d.	Other					
C. Process Instrumentation								
	1. Pressure Control							
		a.	Fisher					
		b.	Foxboro					
		c.	Taylor					
		d.	Other					

Control Panels								
	2. Temperature Control							
		a.	Foxboro					
		b.	Taylor					
		c.	Kimray					
		d.	Other					
	3. Pressure Sensors							
		a.	Fisher 4660					
		b.	WKM					
		c.	Axelson					
		d.	Autoguard					
		e.	AMOT					
		f.	Baker					
		g.	Other					
D. Panel Manufacturers								
	1.	Autocon						
	2.	Automation USA						
	3.	NLS Controls						
	4.	Offshore Controls Systems, Inc.						
	5.	T.E.S.T.						
	6.	Magnum Valve						
	7.	Other						

Controllers and Control Theory

EPT 05-T-02

October 1992 Draft

Version 0

Table of Contents

1. Scope 6

2. References 6

2.1. MEPS–Mobil Engineering Practices 6

2.2. Mobil Tutorials 6

2.3. CHILTON–Chilton 6

3. Control Philosophy 6

3.1. Local Control 7

3.2. Central Control 9

3.3. Distributed Control 12

3.4. Control Philosophy Selection 15

4. Control Theory 15

4.1. Open Loop Concept 15

4.2. Closed-Loop Concept 16

4.3. On/Off Control 19

4.4. Proportional Control 21

4.5. Proportional-Plus-Integral Control 28

4.6. Proportional-Plus-Integral-Plus-Derivative Control 33

4.7. Digital Control 39

5. Controller Principles and Selection 39

5.1. Local Controllers 39

5.2. Panel-Mounted Controllers 43

5.3. Digital Controllers 48

5.4. Distributed Control Systems 51

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6. Loop Configurations 51

6.1. Single-Variable Feedback Control 51

6.2. Feed-Forward Control 52

6.3. Cascade Control 53

6.4. Multivariable Loops 54

7. Controller and Loop Tuning 54

7.1. 54

7.2. 55

7.3. 55

7.4. 55

7.5. 56

7.6. 56

7.7. 57

7.8. 57

7.9. 57

7.10. 57

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Table of Figures

Figure 1: Two Types of Local Controllers (Courtesy of the Foxboro Co. and Fisher Controls International, Inc.) 7

Figure 2: A Schematic of a Yoke-Mounted Local Pressure Controller 8

Figure 3: Central Pneumatic-Control Panel (Courtesy of Taylor Instrument Division of Combustion Engineering Co.) 9

Figure 4: Central Analog-Electronic Panel (Courtesy of Taylor Instrument Division of Combustion Engineering, Inc.) 11

Figure 5: Diagram of Distributed Process Control 13

Figure 6: Diagram of a Typical DCS System 14

Figure 7: Examples Showing Open-Loop Control 16

Figure 8: An Example of Manual and Automatic Closed-Loop Control 18

Figure 9: A Schematic Showing Gap-Action Control 20

Figure 10: Schematic Showing Proportional-Only Control with the Proportional Band Properly Adjusted 26

Figure 11: Schematic Showing Proportional-Only Control with the Proportional Band Set Too Narrow 27

Figure 12: Schematic Showing the Open-Loop Response of Proportional-Plus-Integral Action 30

Figure 13: Schematic Showing the Proportional-Plus-Integral Control Response in a Feedback Loop 31

Figure 14: Idealized Open-Loop Response of Proportional-Plus-Integral-Plus-Derivative Controller 35

Figure 15 Comparison of Two- and Three-Mode Control for a Temperature Loop 36

Figure 16: Comparison of Two- and Three-Mode Control for a Flow Loop 38

Figure 17: Photograph of a Typical Local-Pneumatic Pressure Controller (Courtesy of Fisher Controls International, Inc.) 40

Figure 18: Schematic of Auto/Manual Option for Local Controller (Courtesy of Fisher Controls International, Inc.) 43

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Figure 19: Photograph of a Panel-Mounted Pneumatic Controller (Courtesy of the Foxboro Co.).....45

Figure 20: Photograph of Panel-Mounted Analog-Electronic Controller (Courtesy of Moore Products Co.).....47

Figure 21: Examples of Digital-Controller Loops (Courtesy of Powell Process Systems, Inc.).....50

Figure 22: Examples of Single-Variable Feedback Control.....52

Figure 23: Feed-Forward Control Scheme for a Wellstream Heater.....53

Figure 24: Example of Cascade Control.....53

Figure 25: Schematic Showing Typical Antisurge Control Loop.....54

Figure 26: Proportional Band Responses in Different Conditions 56

1. Scope

This tutorial introduces the principles of control and the popular methods of implementation. The basic concepts of systems used are covered so that the user may make appropriate choices for particular applications. Technical facts and general guidelines are provided for the user to apply to projects' special circumstances in the selection of a control philosophy and its implementation. Also presented are basic control loop tuning practices.

2. References

The following Mobil guides and industry publications shall be considered a part of this EPT. Refer to the latest editions unless otherwise specified herein.

2.1. MEPS–Mobil Engineering Practices

MP 32-P-01	General Requirements for Instrumentation
MP 32-P-14	Programmable Logic Controllers
MP 32-P-16	Distributed Control Systems

2.2. Mobil Tutorials

EPT 05-T-09	Distributed Control Systems (DCS)
EPT 05-T-10	Programmable Logic Controllers (PLC)

2.3. CHILTON–Chilton

CHILTON	Instruments Engineer's Handbook (2 Volumes): Process Measurement and Process Control

3. Control Philosophy

Control philosophy is governed by operations philosophy and personal preferences, as well as by technical considerations. This section addresses the technical considerations that help the engineer apply these factors and develop a satisfactory control system. Most control problems can be solved satisfactorily and within good engineering practice in more than one way.

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3.1. Local Control

3.1.1.

Local controllers sense the process variable (generally this is done directly) and develop an output to control a valve or other end device. These controllers are almost always pneumatic, with either instrument air or instrument gas supplied from a distribution system through a filter and pressure regulator. Local controllers are usually mounted throughout the facility as near to the sensing and control points as practical. Figure 1 shows two popular local controllers.

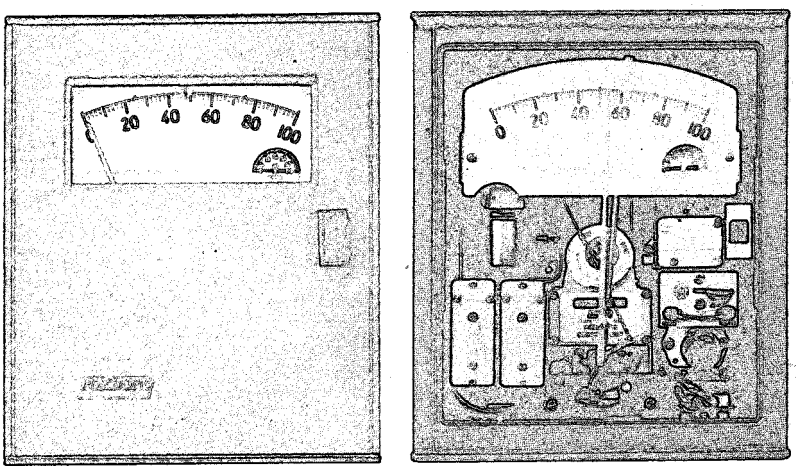

Figure 1: Two Types of Local Controllers (Courtesy of the Foxboro Co. and Fisher Controls International, Inc.)

3.1.2.

Local control loops are familiar sights in production and processing facilities. Some examples include a pressure controller that is connected to the process by tubing to sense the pressure and mounted on a valve yoke, a level controller mounted on a vessel, or a flow controller connected to an orifice fitting and mounted on a pipe stand. All these controllers will have an air or gas supply and typically develop a 20 to 100 kPa or 40 to 200 kPa (3 to 15 or 6 to 30 psig) signal that controls a valve. Figure 2 shows a pressure controller mounted on a control valve yoke as an example of a local control loop.

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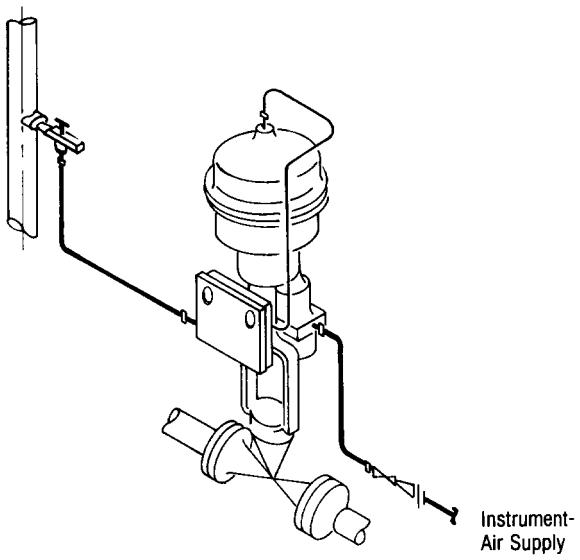

Figure 2: A Schematic of a Yoke-Mounted Local Pressure Controller

3.1.3.

Almost all facilities use some local control. Even large complexes with highly centralized control systems have some loops that are more practical to control locally. Small oil and gas production facilities are usually entirely on local control. In general, the smaller the facility and the less critical the loops, the more dominant are local control loops.

3.1.4.

The biggest advantages of local control are low cost and simplicity. Equipment cost is low because only the controller and the end device are needed. Local controllers usually cost more than panel-mounted controllers, but do not need a transmitter. The control valve shall be needed either way, but often a positioner or transducer can be omitted. Tubing or wire runs to a control room are not needed for local control.

3.1.5.

The obvious disadvantage of local control is that it is difficult for any one person to monitor the entire operation of any but the smallest of facilities. Problems may take longer to detect and correct because it is difficult to see the overall picture.

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3.2. Central Control

Central control is the concept of locating controllers in a central panel, usually located in a control room at a central location within the facility. This concept generally requires that process conditions are monitored through signal transmitters which are then cabled or tubed to the central control panel. Central control provides the means for observation and control of the total facility from a central location.

3.2.1. Pneumatic

1. Figure 3 shows a central pneumatic-control panel.

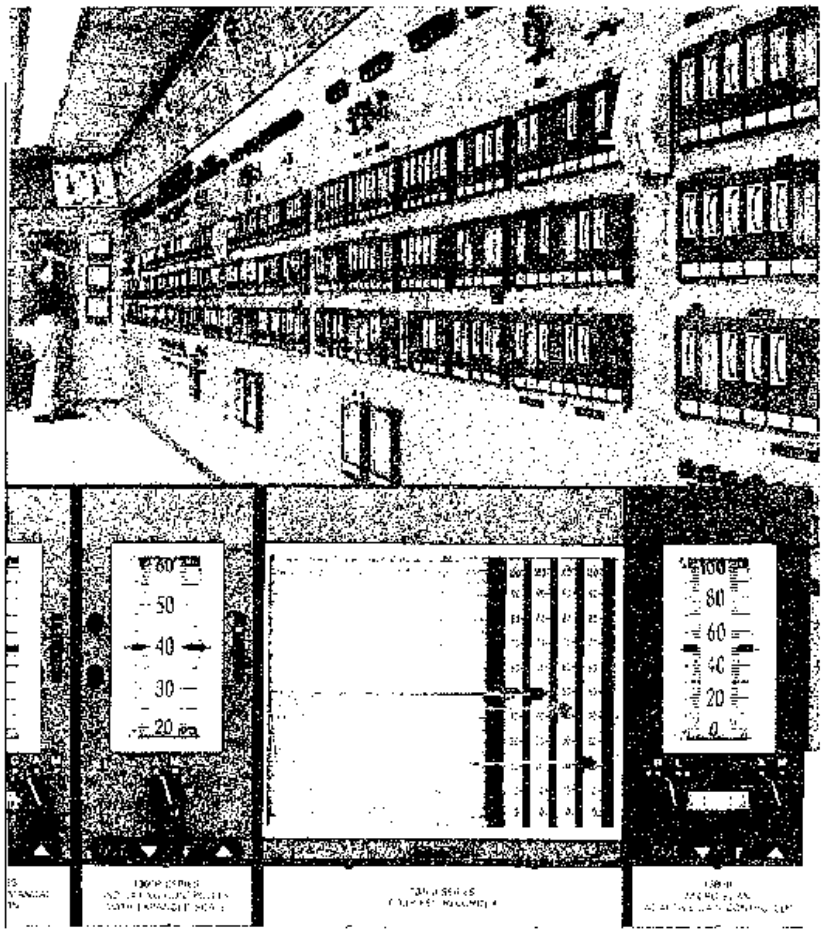

Figure 3: Central Pneumatic-Control Panel (Courtesy of Taylor Instrument Division of Combustion Engineering Co.)

2. Pneumatic transmission uses a 20 to 100 kPa (3 to 15 psig) signal as a standard. Controllers are specified with 40 to 200 kPa (6 to 30 psig) outputs so that valve actuators can supply the needed power to operate

smaller vales without a positioner. Standardized signals allow mixing of products from different manufacturers.

3. The long runs of tubing that are required from central-analog-pneumatic control introduce significant delay between a change in the process and the resulting change of signal to the valve. The amount of delay depends on the size of the tubing, the volume of the receivers, and the nature of the supplying device. A rough rule of thumb is about 1 second of delay for every 30 m (100 ft) of tubing run. Distances between the controller and the process of up to about 100 m (350 ft) are usually not a problem. Where long runs are required, signal booster relays shall be employed.

4. Large facilities require large control rooms with long control panels equipped with large numbers of similar-appearing controllers and recorders.

5. The use of pneumatic control systems in a central control concept is generally not practical due to the availability of electronic and microprocessor-based controllers. See Section 2.6 of the Chilton Process Control Handbook for a detailed discussion of pneumatic controllers.

3.2.2. Electronics

1. Figure 4 shows a central electronic control panel.

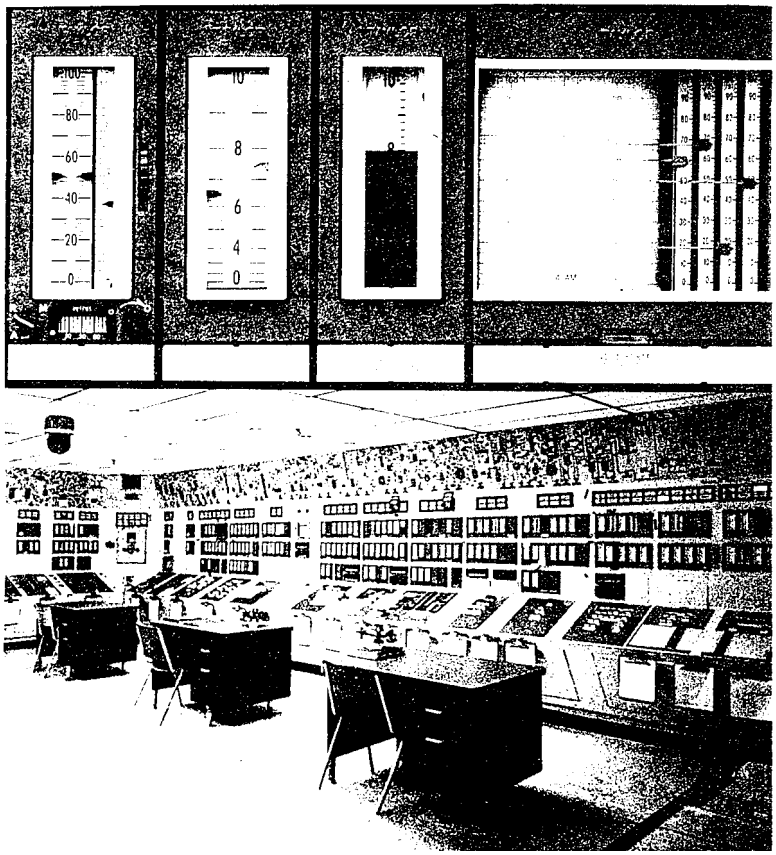

Figure 4: Central Analog-Electronic Panel (Courtesy of Taylor Instrument Division of Combustion Engineering, Inc.)

2. The main advantage offered by electronic instruments is transmission speed. The speed of transmission is almost the speed of light; therefore, transmission time is negligible for real systems. The distance from the process to the controller can be up to several miles with proper conductor selection and is limited primarily by voltage drop in the wiring. Transmitters are current-regulating devices, and the standard transmission level is 4 to 20 mA. Using current for transmission rather than voltage avoids loss of accuracy with long wires or possible high resistance connections.

3. A further advantage is gained in the application of microprocessor-based controllers. Microprocessor-based controllers (single or multiple loop) operate on the same basic principles (proportional, integral, and differential) as the pneumatic or electronic controllers, except that they function in a digital format, they are programmable, and they include data storage and data manipulation. These controllers are directly compatible with host computers or DCS (Distributed Control Systems), and they generally use "smart" transmitters that provide loop calibration from the central facility.

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4. Microprocessor-based controllers are generally applied in single unit control applications such as compressor surge control systems or other batch-type control functions.

5. See Section 2.3 of the Chilton Process Control Handbook for detailed discussions of electronic controllers.

3.3. Distributed Control

3.3.1.

Distributed Process Control is the application of individual control systems to specific unit control functions. These individual control systems are then interconnected (usually with the operator interface at a central control room) to provide a uniform total facility control system.

3.3.2.

Figure 5 shows a typical distributed process control system commonly known as a "hybrid system". It has this name because it consists of a mixture of standard controls systems combined with a computer and appropriate SCADA (Supervisory Control and Data Acquisition) software to complete the system. Figure 6 shows a typical DCS system. A DCS is a form of industrial process control that use the concepts of distributed controllers to provide a highly reliable facility control system, as opposed to a "PLC", which can be deemed a unit control system.

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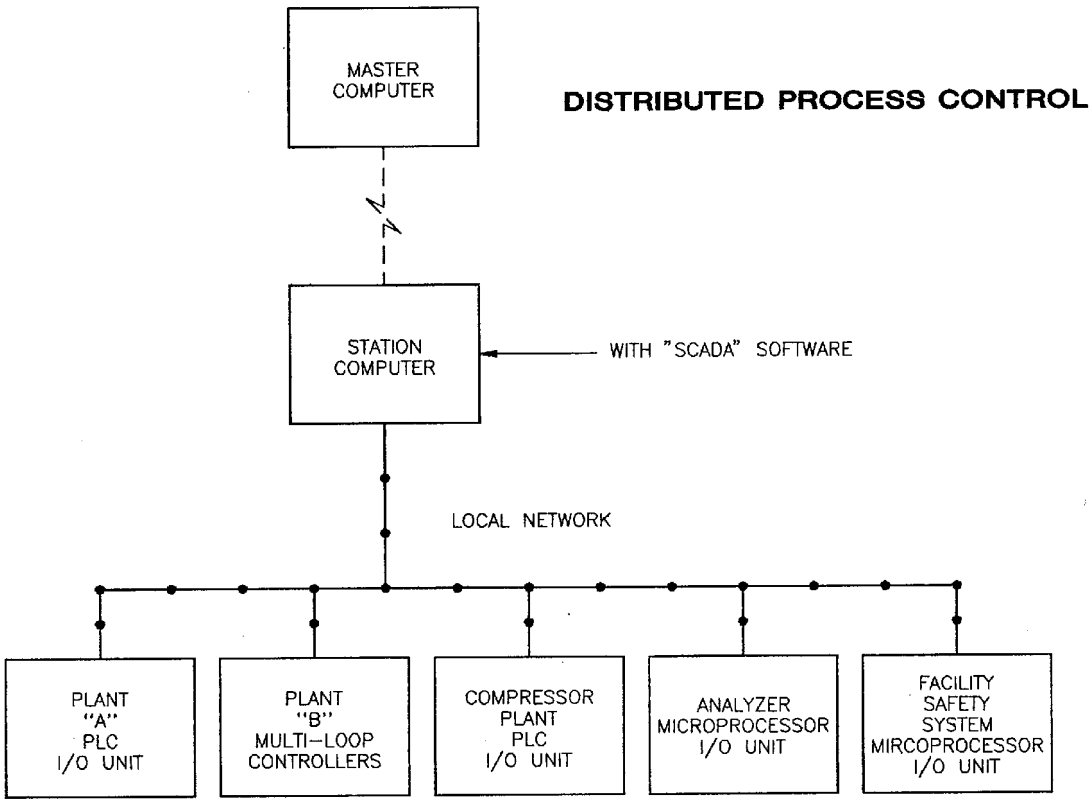

Figure 5: Diagram of Distributed Process Control

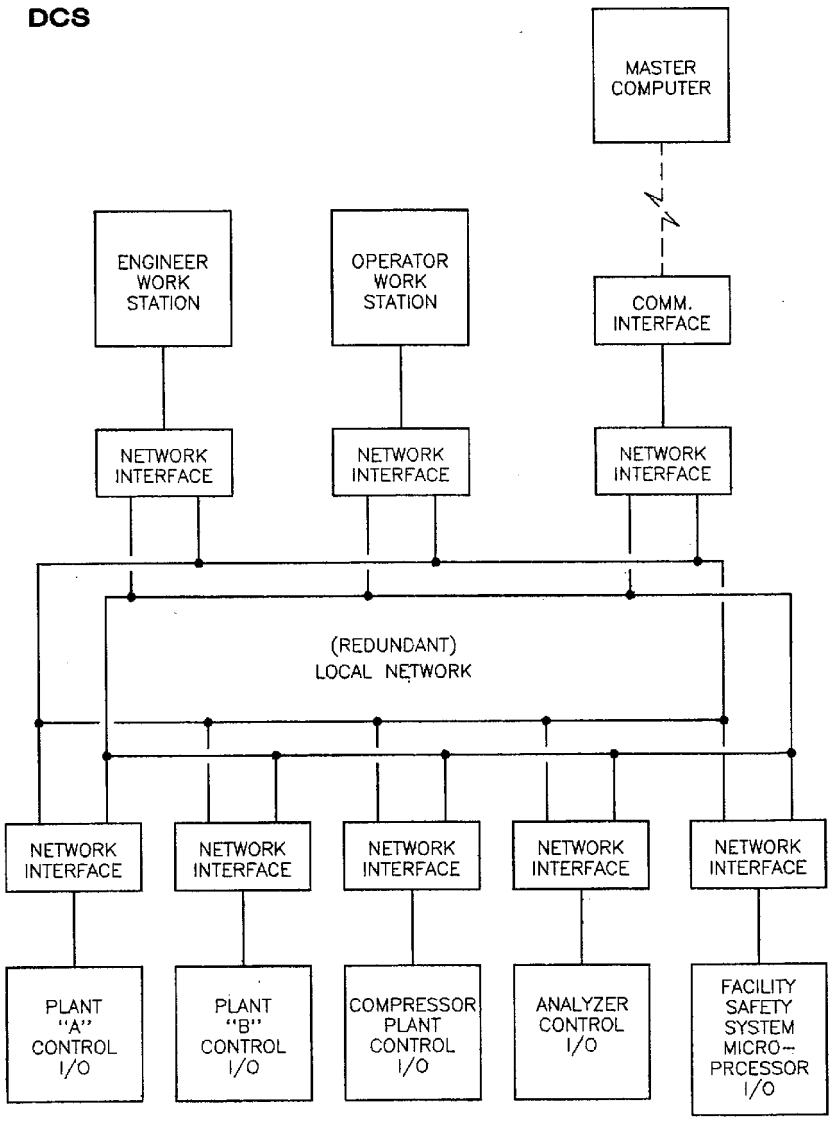

Figure 6: Diagram of a Typical DCS System

3.3.3.

Refer to the tutorials EPT 05-T-10 on PLC and EPT 05-T-09 on DCS for information about these systems.

3.4. Control Philosophy Selection

3.4.1.

Operations philosophy and personal preference are important in selecting a control system for a particular installation. There are usually several solutions that can be considered correct and good practice.

3.4.2.

Small installations lend themselves well to local control. Installations with only one or two vessels which are too small to have a control room are almost always controlled by local pneumatic controllers. Electronic controllers are used where central or remote control is applicable.

3.4.3.

A mixture of local control and central control is sometimes selected for medium-sized installations. Critical loops and loops that shall be electronic are brought into the control room, while loops deemed less critical are controlled locally. Selection of which loops to bring into the control room is sometimes obvious, but in some cases it requires careful consideration. Large facilities generally require the application of some form of distributed process control.

3.4.4.

Refer to the tutorials EPT 05-T-10 on PLC and EPT 05-T-09 on DCS for details on these control systems and their application.

4. Control Theory

4.1. Open Loop Concept

The simplest form of control is open loop. No information from the controlled variable is used to determine or modify the control action. Open loop control is used where the consequence of the control action can be adequately predicted in advance of the action. Some everyday examples are the wall switch to turn on the light, the faucet to water the lawn, and the timer to water the lawn for 30 minutes every morning at 5:00 a.m. Figure 7 shows examples of open loop control.

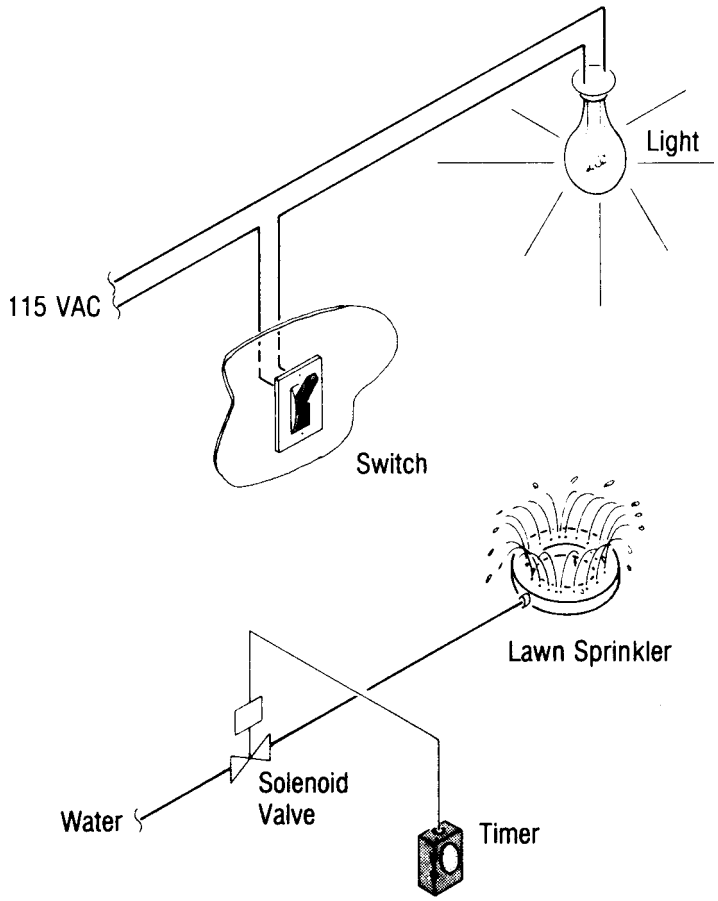

Figure 7: Examples Showing Open-Loop Control

4.2. Closed-Loop Concept

4.2.1.

In closed-loop control, some information about the controlled variable shall be made available to the controller to ensure proper control. Returning this information is known as closing the loop, or feedback. Everyday examples of this are watching the swimming pool level and turning the water off when it is full, or a thermostat that turns the air conditioner or heater on and off at a preset temperature.

4.2.2.

Manual control will work for almost any process control application, but it may require constant attention. Some controls are used seldom enough or are stable enough that manual operation is practical. Most automatic controllers

can be purchased with an auto-manual selector so that the operator can use manual control if needed.

4.2.3.

These examples demonstrate the principle of closed-loop control, but most process controls are a bit more complex than these. A process variable, usually pressure or level of flow, is measured, and the measurement is conveyed directly or through a transmitter to a process controller. The controller generates a signal to control an end device, which is usually a valve, but sometimes engine speed, louvers, or other apparatus. The controller attempts to maintain the process variable at a predetermined value (set point) by manipulating the end device. The following sections discuss how the controller does that. Figure 8 shows examples of closed-loop control. Table 1 shows when the various types of control are used.

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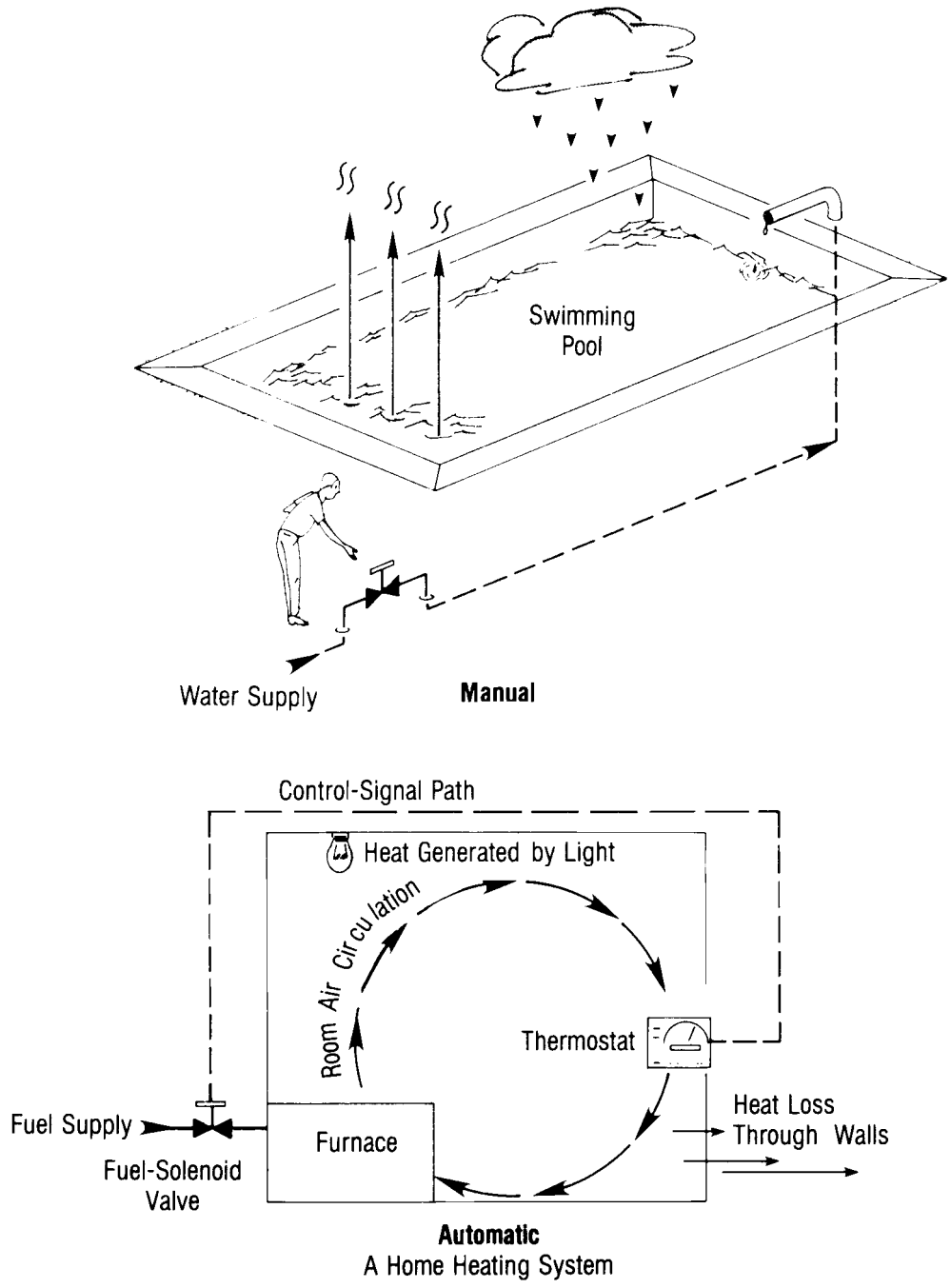

Figure 8: An Example of Manual and Automatic Closed-Loop Control

Table 1

Type Control	Typical Uses
Gap-Action or on/off	Level control with small liquid flow rates. Pump control from storage tank level.
Proportional only	Most level controls. Gas-pressure control.
Proportional & Integral	Liquid-pressure control. Flow control. Critical liquid level.
Proportional & Integral & Derivative	Temperature control. Vapor-pressure control. Composition control (from analyzer sensors).

4.2.4.

Refer to Section 1.4 of the Chilton Process Control Handbook for a detailed discussion of closed loop control.

4.3. On/Off Control

4.3.1.

The simplest form of automatic control is on/off. The end control device has only two possible states: fully open or fully closed in the case of a valve, or full speed or stopped in the case of rotating equipment. On/off control is used for level control much more often than for other process variables, but it is also frequently used for control of air compressors, pumps, fired vessels, etc.

4.3.2.

On/off control implies that the control system is implemented by switches rather than a controller. The switches can be connected so that a high-level switch opens the valve to dump some liquid, and when the level decreases the desired amount, the valve closes. Likewise, a pump can be started at the high level and stopped at the lower level. Two switches can be used to implement this scheme, or one switch with adequate dead band can be used.

4.3.3.

Several manufacturers can provide controllers for on/off level control. These controllers are usually known as gap-action, snap-action, or differential-gap controllers. They typically use a vertical displacer, which can be inside the

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vessel or in an external cage. The controller is mechanically connected to the displacer and is used for local-pneumatic control. There are two adjustments on most controllers. One adjustment sets the center of the gap and the other adjusts the length of the gap. The controller is usually installed so that the center of the gap is near the center of the displacer. The gap length can be adjusted from seven percent to nearly 100 percent of the displacer length, depending on the manufacturer and model. Typical controller action is shown in Figure 9.

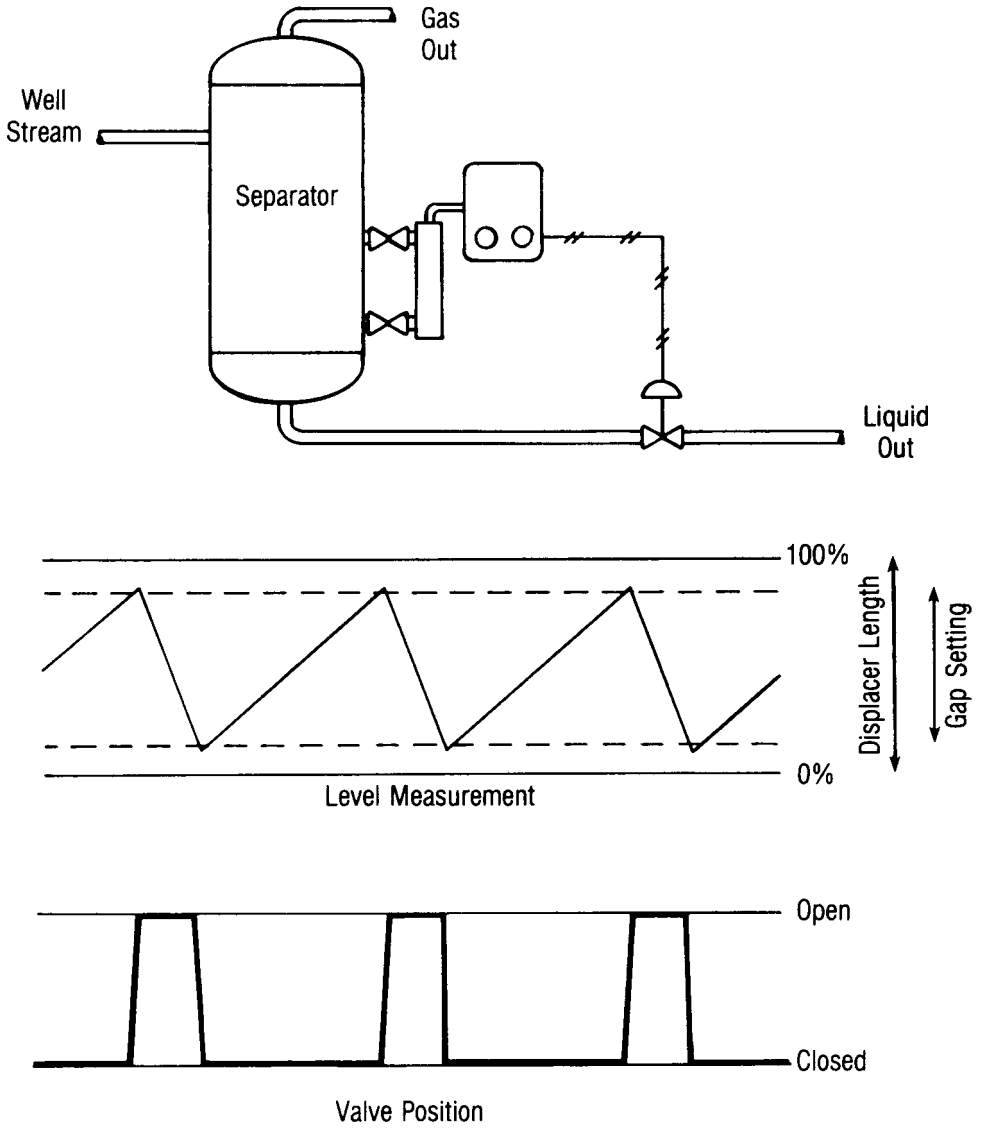

Figure 9: A Schematic Showing Gap-Action Control

4.3.4.

On/off control is particularly useful for level control when the flow rate of liquid to dump is usually small but may vary a great deal. It reduces the wear

on a control valve that would be caused by throttling nearly closed, yet it allows use of a valve large enough to handle the peak rate. Also, it allows measurement of small quantities with standard flow measurement devices by intermittently allowing a flow rate large enough to be accurately measured.

4.3.5.

On/off control is not recommended when the rates are so high that process upsets may be caused by valves opening and closing or rotating equipment starting and stopping. Also, water-hammer and mechanical wear caused by starting and stopping shall be considered.

4.3.6.

Refer to Section 1.2 of the Chilton Process Control Handbook for a detailed discussion.

4.4. Proportional Control

4.4.1.

Proportional control is the basis for modern control theory. With the exception of on/off control, the other control actions are used in conjunction with proportional control.

4.4.2.

Before control theory can be explained, a number of terms shall be introduced.

1. Process variable is the process characteristic that is to be controlled. Pressure, level, flow rate, and temperature are the most common examples.
2. Measured range is the range of the process variable that the controller can measure. Whether the measurement is direct or through a transmitter, it is the actual process measurement and not the signal from the sensing device.
3. Set point is the desired value of the process variable and the controller adjustment that communicates this value to the controller.
4. Error is the difference between the value of the process variable and the set point.
5. Offset is the error present after the controller has made its correction and the process has stabilized.
6. Droop and overpressure are the same as offset, usually applied to self-contained pressure regulators.

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7. Bias is the output of the controller when the process variable is at the set point and no error or offset is present.

8. Proportional band is expressed in percent and is the portion of the measured range over which the controller output goes from minimum to maximum.

9. Gain is another term sometimes used to express sensitivity. Gain is the percentage change in output divided by the percentage error, and it is also the inverse of the proportional band.

Equation 1

$$G = \text{percent output change} / \text{percent error}$$
$$= 100 \text{ percent} / PB$$

where :

$G = \text{gain}$

$PB = \text{proportional band in percent}$

4.4.3.

The output of a proportional-only controller is always the bias when the process variable is at the set point. This bias is usually fixed at the midpoint of the controller output by the manufacturer. A 20 to 100 kPa (3 to 15 psig) pneumatic controller shall have a bias of 60 kPa (9 psig), and a 4 to 20 mA controller will have a bias of 12 mA. The output shall vary from the bias when an error is present. The relationship between the output and the error is linear over the proportional band according to the following formula:

Equation 2

$$\text{Output} = 100e / PB + b$$

where :

$\text{Output} = \text{percent of controller output}$

$e = \text{error in percent of measured range}$

$PB = \text{proportional band in percent of measured range}$

$b = \text{bias in percent output}$

4.4.4.

A proportional-only controller has two primary user adjustments, the set point and the proportional band.

4.4.5.

The set point, as defined above, is the adjustment that communicates the desired process-variable value to the controller. Usually, the set point is entered by the operator using a readily accessible adjustment. Some controllers can accept a remote set point adjustment from another controller, computer, or other device. The set point can be anywhere within the measured range, but it is preferable to choose a range so that the set point is at or near the center.

4.4.6.

The proportional band setting determines the sensitivity of the controller. This adjustment is usually inside the case because it does not need to be adjusted frequently. Proportional band is expressed as the percentage of the measured-variable range over which the output varies from minimum to maximum. Proportional bands larger than 100 percent are available from most manufacturers for use in combination with integral control, but settings over 100 percent shall not be used for proportional-only controllers. The maximum proportional band setting that shall allow the controller output to vary over its full 0 to 100 percent range is twice the percentage difference between the set point and 100 percent or 0 percent, whichever is smaller. For example, if the set point is at 75 percent of the pressure range, a proportional-band setting greater than 50 percent (2x[100-75]) will prevent the controller output from varying over its entire 0 to 100 percent range whenever the measured variable varies over its entire 0 to 100 percent range.

4.4.7.

To better understand this, review the following example:

A pneumatic, 20 to 100 kPa (3 to 15 psig), proportional-only controller has a pressure range of 0 to 3450 kPa (0 to 500 psig), set point of 1900 kPa (275 psig), measured pressure of 2240 kPa (325 psig), and proportional band setting of 50 percent. The controller output can be calculated as follows:

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$$error = 100 \times \frac{(2240 - 1900)\,kPa}{3450\,kPa} = 10\ percent$$

or

$$error = 100 \times \frac{(325 - 275)\,psig}{500\ psig} = 10\ percent$$

$$output = \frac{100 \times 10}{50} + 50 = 70\ percent$$

$$output = (100 - 20)\,kPa \times 70 = 56\ kPa\ above\ base$$

or

$$output = (15 - 3)\ psi \times 70 = 8.4\ psi\ above\ base$$
$$output = 20\ kPa\ base + 56\ kPa = 76\ kPa$$

or

$$output = 3\ psig\ base + 8.4\ psi = 11.4\ psig$$

4.4.8.

If the loop stabilizes at this condition, the pressure shall be controlled at 2240 kPa (325 psig) instead of at the 1900 kPa (275 psig) set point. The 340 kPa (50 psi) difference is the offset. Some offset is inherent with proportional-only control unless conditions are exactly right for the control valve to be in the correct position with the output equal to the bias. This bias can usually be adjusted for a pneumatic controller by resynchronizing controller output to equal the bias when process indicator and set pointer are together.

4.4.9.

In this example, if the loop stabilizes at the 76 kPa (11.4 psig) controller output, the process pressures that would cause this output if the proportional band were set at 25 percent, can be calculated from the following equations:

$$output = \frac{100 \times e}{25} + 50 = 70 \ percent$$

or

$$e = \frac{(70 - 50)25}{100} = 5 \ percent$$

$$process \ pressure = set \ point + error$$

$$process \ pressure = 1900 \ kPa + \frac{3450 \times 5}{100} = 2070 \ kPa$$

or

$$process \ pressure = 275 \ psig + \frac{500 \times 5}{100} = 300 \ psig$$

4.4.10.

The offset has been halved by halving the proportional band or doubling the gain. The advantage of narrowing the proportional band is demonstrated by the example, but the disadvantage is not as readily apparent. The action of the controller is very nearly instantaneous, but the valve movement and its effect on the process are not. If the proportional band is narrowed enough that the error can develop faster than the control loop can correct it, the loop shall become unstable, and the control value shall cycle between fully open and fully closed without controlling the process variable. Figure 10 shows proportional control with the proportional band properly adjusted. Figure 11 shows the effect of a proportional band setting that is too narrow.

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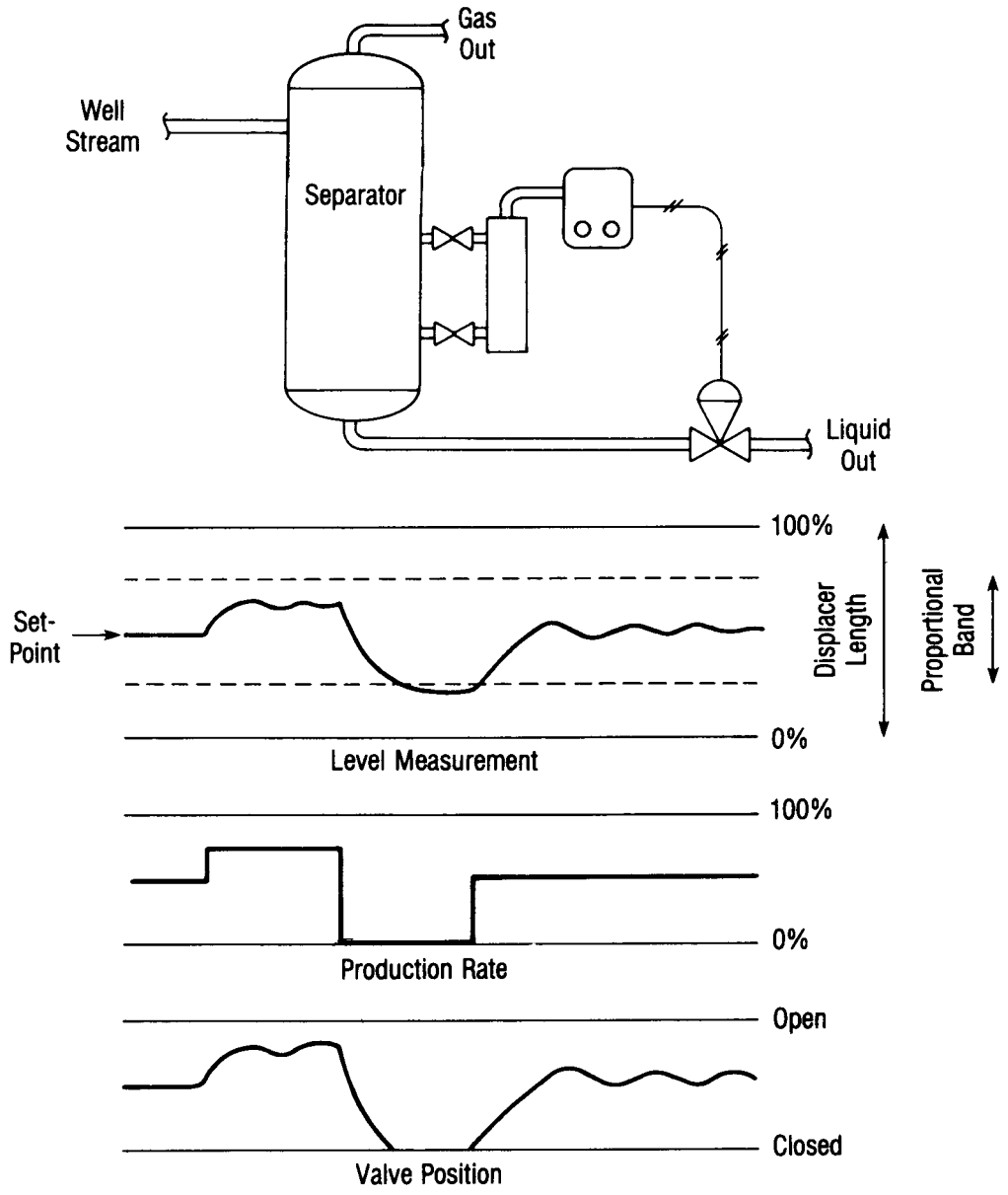

Figure 10: Schematic Showing Proportional-Only Control with the Proportional Band Properly Adjusted

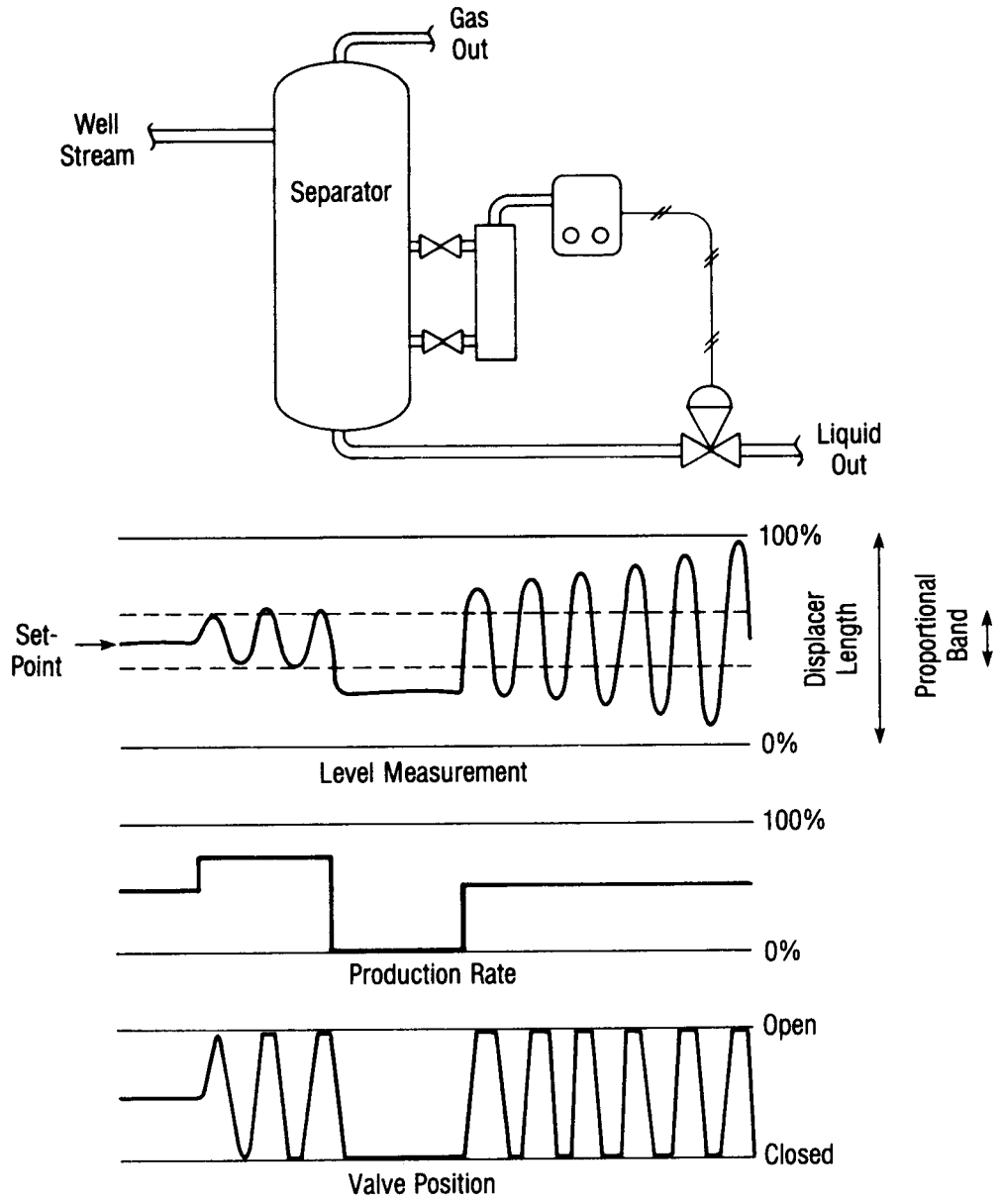

Figure 11: Schematic Showing Proportional-Only Control with the Proportional Band Set Too Narrow

4.4.11.

Slow-reacting loops are good candidates for proportional-only control. Level-control loops for tanks and vessels, as well as pressure loops for compressible fluids, are examples. Offset of approximately ± 8 cm (3 in) for level and ± 10 percent for pressure are normal for proportional-only control. Self-contained level controllers for proportional-only control are available from several manufacturers. Proportional-only pressure controllers are also

available, but a self-contained pressure-regulator valve is usually a more economical choice.

4.4.12.

Fast-reacting loops, such as that for pressure control of noncompressible fluids and that for flow control, are seldom good candidates for proportional-only control. Temperature loops may be good candidates if there is a large heat sink, such as a water bath heater and a tank heater. Louver controls and exchanger bypasses are usually not good candidates.

4.4.13.

The range of proportional band adjustment varies somewhat from one manufacturer to another, but all popular brands offer adequate adjustment. The available proportional band adjustment is very rarely an important criterion in choosing a manufacturer.

4.4.14.

Controllers can be configured so that the output rises when the process variable is above the set point, referred to as "direct acting". They can also be configured so that the output decreases when the process variable is above the set point, referred to as "reverse acting".

4.4.15.

Refer to Section 1.2 of the Chilton Process Control Handbook for more details.

4.5. Proportional-Plus-Integral Control

4.5.1.

Offset can be eliminated by adding integral action to proportional control. Integral action (also called reset action) is an integration of the error over time. This means that the controller response shall depend on both the size and duration of the error. As long as there is an error from the set point, the controller shall continue to drive its output in the direction that will reduce the error. Integral control can be thought of as automatically changing the bias until the offset is eliminated. The speed of that response will be proportional to the magnitude of the error and the integral time.

4.5.2.

The formula for proportional-plus-integral control is:

Equation 3

$$Output = \frac{100}{PB} \times \left(e + R \int_{o}^{t} e\, dt\right) + bias$$

where :

$Output = percent\ of\ controller\ output$

$e = error\ in\ percent\ of\ measured\ range$

$PB = proportional\ band\ in\ percent\ of\ measure\ range$

$R = integral\ gain\ in\ repeats\ per\ minute$

4.5.3.

Integral controls are calibrated in, referred to as integral gain. Increasing the integral gain increases the amount of integral action. The amount of correction to the output caused by proportional response to the error will be added to the bias every integral time period. If the process does not respond to the correction, the output shall drive to either its high or its low limit.

4.5.4.

Figure 12 illustrates the open-loop response of proportional-plus-integral action. The process measurement is initially at 50 percent of the scale. Since the process measurement is at the set point, there is no proportional action or integral action, and the controller output is at the bias level of 50 percent. The process measurement is reset to 75 percent of the scale at the one-minute mark. The proportional action immediately increases the output to 62.5 percent, calculated by using Equation 3. It shall be noted that integral output is zero at time zero. Proportional control acts in this "zero" time interval to establish bias (repeat/minute).

$$Output = (100 / 200) \times (75 - 50) + 50$$

$$= 62.5$$

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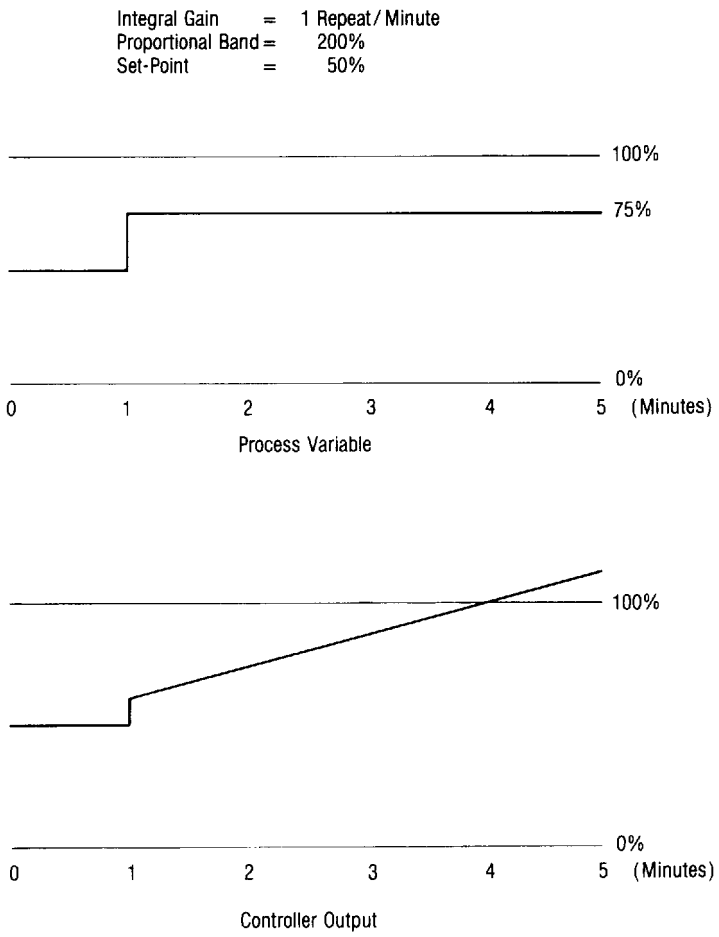

Figure 12: Schematic Showing the Open-Loop Response of Proportional-Plus-Integral Action

4.5.5.

The integral action then increases the bias at the same rate as the proportional correction each integral time period; that is, at 12.5 percent of the output range each minute for this example.

4.5.6.

The process does, of course, respond to control action in real control loops. The almost immediate initial response of proportional action limits the developing error, and then the integral action starts moving the bias to eliminate the error. The integral action is most rapid at first, but it slows as the process returns to set point because it is proportional to both the error and the integral time. The process variable shall return to the set point and stabilize if the controller is tuned properly. Figure 13 shows proportional-plus-integral response in a feedback loop.

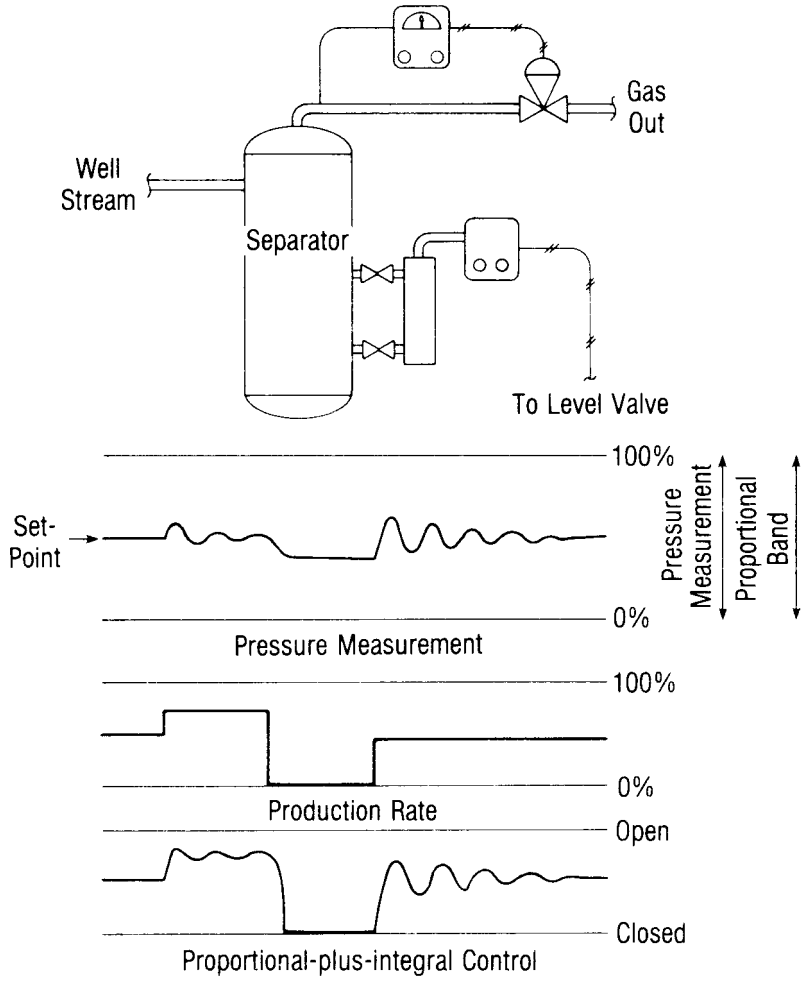

Figure 13: Schematic Showing the Proportional-Plus-Integral Control Response in a Feedback Loop

4.5.7.

With proportional-only action, control becomes unstable if the proportional band is too narrow because a small error can develop and drive the output to a limit before the error can be corrected. The control loop shall respond faster than the process for stability. This is true because the amount of correction depends only on the error and the proportional band and not on the length of time the error is present.

4.5.8.

The proportional band can be set as wide as necessary to prevent instability when integral action is also present. Settings larger than 100 percent are often used. As explained previously, such wide settings would prevent the controller from producing its full output range in proportional-only control.

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But integral actions cause the bias to change and thus will allow the controller output to reach either limit after a period of time, no matter how wide the proportional band is set.

4.5.9.

Integral action depends on both the error and the length of time that it is present, so integral action shall have a slower response than the process for stability. Integral action will continue to change the bias until the error is eliminated. If integral action is set too sensitive (small minutes/repeat setting) the output can drive to its limit before the process can respond, and the control valve will cycle between fully opened and fully closed.

4.5.10.

Integral action can be used for either slow or fast processes to eliminate offset. It is required for stable control of fast processes such as flow control and for most pressure control of incompressible liquids because when the proportional band is wide enough to stop instability, the offset is unacceptable. Slower loops may require integral action if offset is not acceptable. The slower the loop reaction, the longer the integral time required to prevent instability.

4.5.11.

One significant problem with integral control is called reset wind-up. Reset wind-up occurs when the controller cannot bring the process variable back to the set point. This can occur in batch processes that are out of service or bypass loops that are needed only under unusual circumstances. Integral action will drive the controller output to an extreme value even beyond the nominal limits of the output. Figure 12 shows this action where the output goes above 100 percent. Pneumatic outputs can go to full supply pressure or zero pressure rather than stop at 20 or 100 kPa (3 or 15 psig). A similar undesirable result called amplifier saturation can occur in electronic controllers. Controllers can be purchased to limit the output to a preset value, which will minimize the time required for the loop to resume stable control. This option is called anti-reset wind-up by most manufacturers. Controllers that set the output to a preset value when they detect wind-up are also available. These controllers are called batch controllers and are used for intermittent processes to prevent overshoot and allow stability to be reached quickly after start-up.

4.5.12.

Refer to Section 1.2 of the Chilton Process Control Handbook for more details.

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4.6. Proportional-Plus-Integral-Plus-Derivative Control

4.6.1.

Derivative control senses the rate of change of the process variable and applies a correction in proportion to this rate. This allows earlier response than proportional-and-integral control. As the measurement approaches a steady state, the derivative action diminishes, and the correction is completed by proportional and integral action.

4.6.2.

Both proportional and integral control develop corrective action based on the amount of error present and are not sensitive to the speed that the error is developing. Some control loops have considerable lag time between the start of an upset and the time when the full amount of the error is conveyed to the controller. Derivative control, also called rate control, is useful for these loops.

4.6.3.

Derivative action is usually used in conjunction with proportional and integral actions. The formula for proportional-plus-integral-plus-derivative control is:

Equation 4

$$Output = \frac{100}{PB} \times \left(e + R \int_{o}^{t} e \; dt + D \frac{de}{dt} \right) + bias$$

where :

$Output = percent\ of\ controller\ output$

$e = error\ in\ percent\ of\ measured\ range$

$PB = proportional\ band\ in\ percent\ of\ measured\ range$

$R = integral\ gain\ in\ repeats\ per\ minute$

$D = derivative\ setting\ in\ minutes$

4.6.4.

Process measurements that are slow to develop usually exhibit a high rate of change at first but slowly come to the final reading. The classic example of this action is a temperature measurement made by a device in a thermowell. When the process temperature changes, it takes nearly one minute for the reading to approximate the actual temperature. The process fluid shall

change the temperature of the well before it can be sensed. The temperature change of the well will be more rapid at first when the temperature difference is greatest and slow as the temperature difference diminishes. The magnitude of the change can be forecast by the rate of change at the start.

4.6.5.

Figure 14 shows the ideal open-loop response of a proportional-plus-integral-plus-derivative controller. The process variable is increased from 50 percent at the rate of 25 percent per 0.2 minute. The derivative is set at 0.2 minute; therefore, the derivative function will add 15 percent to the output while the process variable is increasing at that rate. This causes the sharp rise in the output curve.

4.6.6.

During the time that the process variable continues to increase, the proportional band contribution to the output is increasing in proportion to the error. Integral is also adding to the output, but its contribution is small compared to the derivative and proportional band.

4.6.7.

When the process variable stops increasing, the contribution from derivative stops and the output falls to about the level that it would be if the controller were proportional-plus-integral. Integral action continues to increase the output to wind-up.

4.6.8.

The curve of Figure 14 is for a theoretical controller. Actual curves will not be as sharply defined but shall approximate these. The process variable will also be affected by the control response in real three-mode controller loops. Figure 15 shows approximately how a real temperature-control loop would respond to step changes in heat demand, allowing for heat sinking of the process and measurement delay of instruments installed in thermowells.

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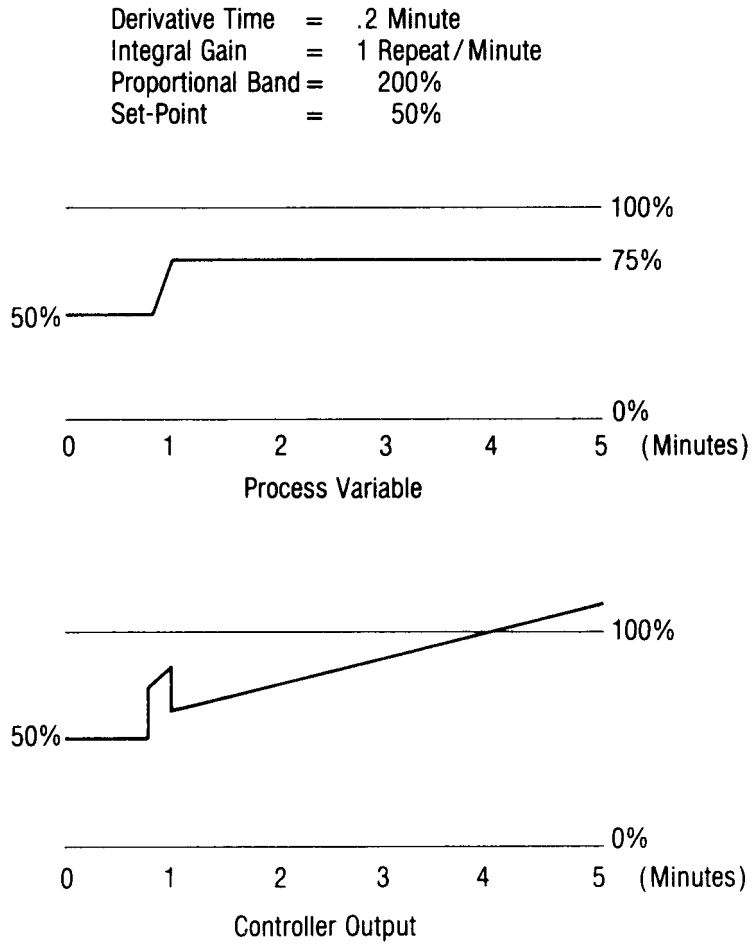

Figure 14: Idealized Open-Loop Response of Proportional-Plus-Integral-Plus-Derivative Controller

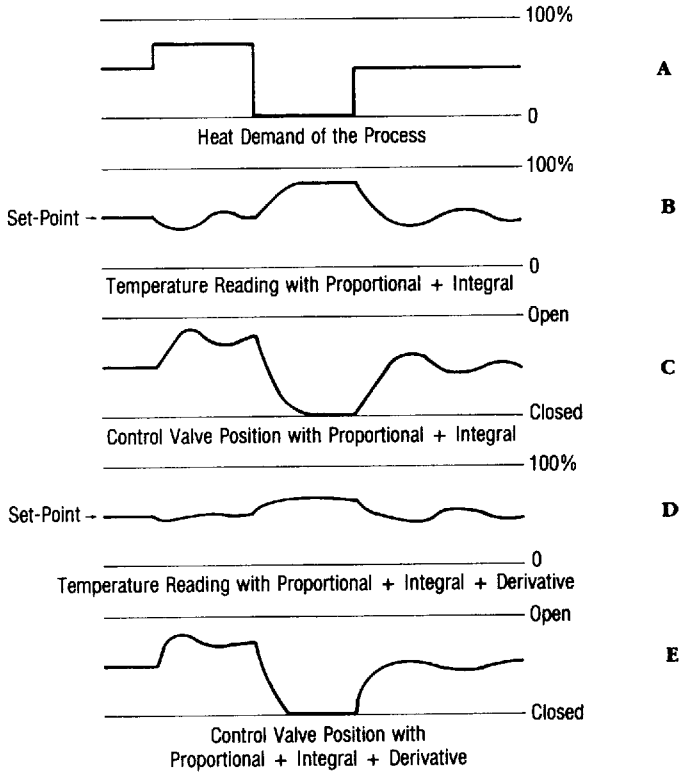

Figure 15 Comparison of Two- and Three-Mode Control for a Temperature Loop

4.6.9.

The sequence starts with the temperature stabilized at the set point. When the process demand for heat changes, as shown in curve A, the temperature starts to drop, as shown in curves B and D. Even though the temperature of the process may drop nearly as rapidly as the change in heat demand, the temperature as measured by the sensor will take some time to stabilize because of the heat-sink effect of the piping, the well, and the measurement element. Since the measurement does not change as fast as the process variable, the rapid correction by proportional action that occurs in faster loops is too small to be very effective and is not seen on the curves.

4.6.10.

Integral action starts moving the control valve (as shown by curve C) and will continue to open the valve at an almost steady rate until the temperature measurement crosses the set point. When the measurement element tells the controller that the temperature is correct, the valve will be too far open and the controller will continue to open and close the valve as the temperature cycles for a period of time. If the proportional band is too narrow or the

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integral time too short, the loop shall be unstable, and the temperature will not be controlled while the valve alternately opens and closes. If the proportional band and integral time are set correctly, the loop shall stabilize after a few cycles, but the temperature will vary farther from the process than if derivative-control action were used.

4.6.11.

Curve E shows the control valve position when derivative control is used in conjunction with proportional and integral controls. Since derivative operates from the rate of change in the process variable, the action is maximum just after the step change in heat demand. Even though the temperature measured just after the change is not very different from the set point, the measurement is changing at a maximum rate, and the controller shall call for the valve to respond rapidly. This action replaces the rapid action of proportional control that is available when the measurement follows the process variable closely. Derivative action also reverses immediately when the measurement crosses the set point. The effect is that the cycling excursions from the set point do not have as much amplitude or last as long with proportional, integral, and derivative as with just proportional-plus-integral control. Compare the smoothness of curve D with that of curve B.

4.6.12.

Derivative control is useful for loops where the measurement is slow to follow the actual change and the rate of change of the measurement is a good indication of the final value of the process variable. It is detrimental for loops where the measurement closely follows the actual condition and the process variable fluctuates rapidly about some trend.

4.6.13.

Derivative control shall never be used for flow-control loops and pressure loops where pulses are present. Figure 16 shows the process variable and controller actions for typical "noisy" loops. The process variable varies rapidly from a fairly constant average value. The proportional-plus-integral controller almost ignores the rapid fluctuations because the proportional band is set very wide and the integral is slow to act. The proportional-plus-integral controller responds to changes in average but not to the noise.

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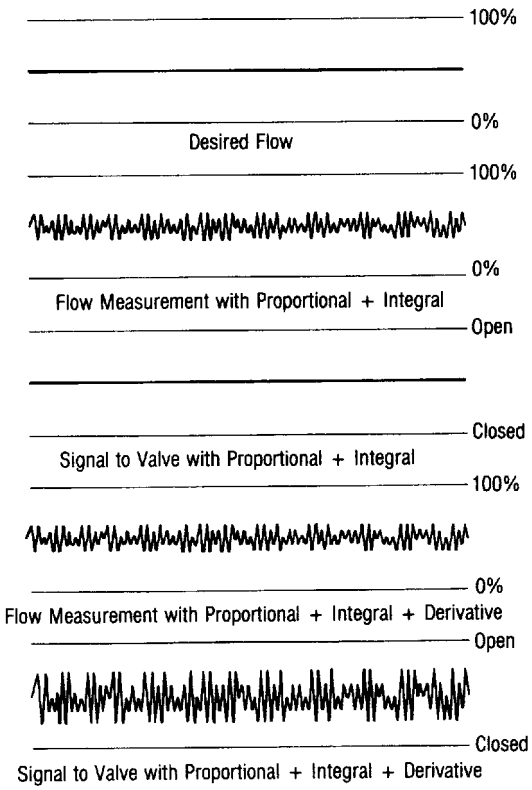

Figure 16: Comparison of Two- and Three-Mode Control for a Flow Loop

4.6.14.

The proportional-plus-integral-plus-derivative controller responds to the rapid pulsations because the derivative action comes from rate of change rather than amount of change. This circumstance causes the noise to increase and may cause loss of control.

4.6.15.

Derivative control is frequently used for temperature control, and it may occasionally be useful for stable-pressure loops. Level loops almost never benefit from derivative control.

4.6.16.

Refer to Section 1.2 of the Chilton Process Control Handbook for more details.

4.7. Digital Control

4.7.1.

Microprocessor technology has allowed development of new controllers with the familiar proportional, integral, and derivative algorithms and almost any other algorithm that can be devised. These controllers can do most mathematical calculations and make logical decisions. They can take several process inputs and deliver several control outputs.

4.7.2.

The range of digital-controller capabilities is large enough and the variation between products offered by different manufacturers is great enough that listing of all of their capabilities in this document is not practical. All of the major manufacturers of controllers offer microprocessor-based controllers, and their representatives can provide applications information. Even though the capabilities of microprocessor controllers are significantly greater than those of analog controllers, their price is often lower.

5. Controller Principles and Selection

5.1. Local Controllers

5.1.1.

Local-pneumatic controllers are available from several manufacturers. The traditional control algorithms of proportional, integral, and derivative are available in controllers for flow, level, pressure, and temperature. Mounting options for surface, control valve yoke, and pipe stand are available for most controllers. Level controllers are usually mounted on the vessel or a bridle.

5.1.2.

A typical pressure controller is shown in Figure 17. This is an indicating controller, and some of the features to note are: the dial and the process-variable pointer are at the top of the case and located so that they can be viewed through a front window when the door is closed. The operator can read the pressure directly from the controller rather than needing an adjacent pressure gauge. Some controllers do not have a process-variable indicator. The set-point adjustment is directly above the process pointer and can be moved anywhere on the dial by the operator. The same calibration applies for the set point and the process indicator, so the operator can easily see what the set point is and whether the process variable is controlled at the set point.

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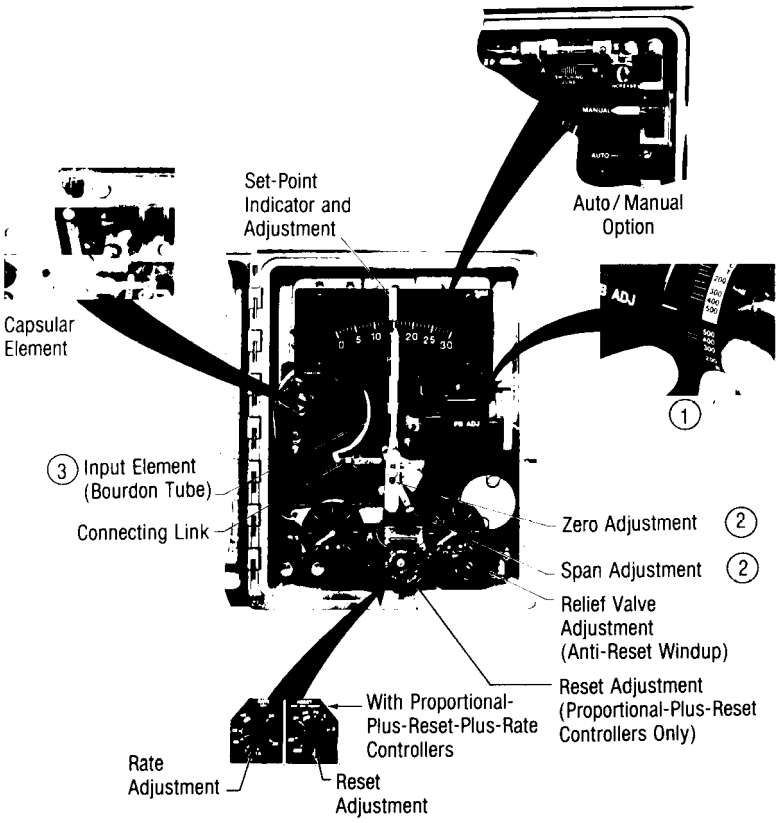

Figure 17: Photograph of a Typical Local-Pneumatic Pressure Controller (Courtesy of Fisher Controls International, Inc.)

5.1.3.

The proportional band adjustment is shown on the right side of Figure 17. This is a wheel calibrated in percent, direct or reverse. The wheel can be positioned for the desired proportional band by hand, but a stop keeps the controller from being changed between direct and reverse acting unless the proportional-band-indicator cover is loosened with a screwdriver. The reset (integral) adjustment is shown bottom center. The reset-and-rate (derivative) controls are shown below and are mounted in place of the reset control to make a three-mode controller.

5.1.4.

Air supply and output-pressure gauges are located at the bottom, and the relief valve for the anti-reset wind-up feature is located just under the output gauge.

5.1.5.

A bourdon tube pressure sensor is shown on the left side of Figure 17. This sensor determines the pressure range measured and is available in convenient increments. Capsular diaphragm elements are available for ranges too low for bourdon tubes. The auto/manual switch is shown in the upper right corner. The manual adjustment knob is just above the switch, and a ball level is installed beside the knob. The manual knob shall be adjusted so that the ball is in the switching zone before transferring from auto to manual to prevent rapid movement of the valve.

5.1.6.

A two-mode controller will have the reset (integral) bellows and reset valve installed. The reset bellows is connected to the output through the reset valve, which is the reset adjustment from Figure 17. As the pressure rises, the reset bellows opposes the proportional bellows and allows the output pressure to increase slowly until force equilibrium of the two bellows and the process variable are reached. The set-point adjustment determines where this equilibrium point will be, and it is calibrated to use the same dial as the process-variable pointer. This means that the equilibrium point is also the set point, and the output will stabilize so that the process variable is at the set point.

5.1.7.

A three-mode controller has a rate (derivative) valve installed in the line to the proportional bellows. This slows the action of the proportional bellows in stopping the output pressure rise. The amount of slowing depends both on the rate adjustment and the rate of change in the process variable. The faster the rate of change, the farther the output pressure can rise before the proportional bellows can stop it. Note that if the rate and reset valves are adjusted so that the pressure rise in the reset bellows is faster than in the proportional bellows, the action of the reset bellows will cause the output to rise very fast and probably cause oscillation.

5.1.8.

Figure 18 shows operational schematics of a popular local-pneumatic three-mode controller. The input element is connected to the process pointer and to the flapper by connecting links. As the process variable increases (in a direct-acting controller), the flapper moves toward the nozzle, restricting flow through the nozzle and increasing nozzle pressure. For reverse action, the proportional band adjustment is rotated so that the nozzle is on the upper portion of the flapper ring, and input element movement has the opposite effect. When this occurs, relay action increases the output pressure (delivery) of the controller. Output pressure is fed back to the proportional bellows and the reset (integral) bellows. The action of the proportional bellows counters the flapper movement that resulted from the process change and backs the flapper away from the nozzle. This establishes a new balance

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point with a higher output pressure than before. A proportional-only controller has only this action. It does not have a reset bellows or reset-and-rate valves, and the output is connected directly to the proportional bellows. The increase in the process variable shall increase the output pressure, and a new equilibrium point will be established, but it will probably not be exactly at the set point, and offset will be present.

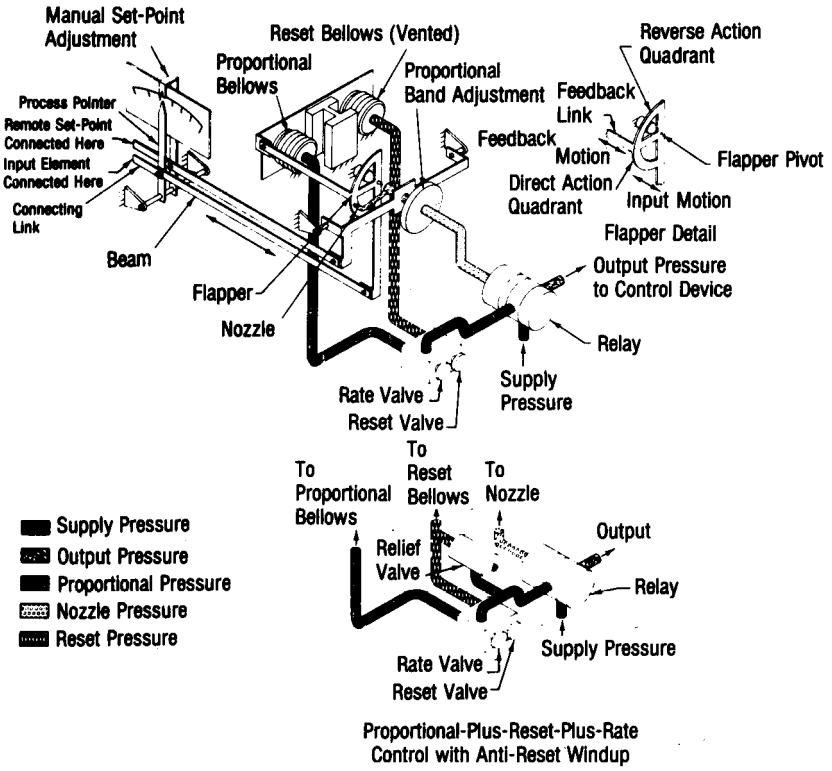

Figure 18: Operational Schematics of a Local-Pneumatic Three-Mode Controller (courtesy of Fisher Controls International, Inc.)

5.1.9.

The small diagram in Figure 18 shows the addition of a relief valve for anti-reset wind-up. This valve is adjusted to open at a preset pressure and equalize the pressure in the reset and proportional bellows. This stops the reset bellows from increasing the output pressure any further and prevents controller wind-up.

5.1.10.

Figure 19 shows the auto/manual system for the controller. The balance indicator is connected between the output pressure and the pressure from the manual loader. To switch from automatic to manual, the manual loader is adjusted to equalize its output with the control output, which is indicated by

centering the metal ball in the plastic tube. The auto/manual switch can then be set to manual and the output adjusted by the manual loader as required. Return to automatic is made by either adjusting the process variable to the set point or by adjusting the set point to the process variable and then setting the switch to automatic. These procedures will prevent sudden valve repositioning when the transfer is made.

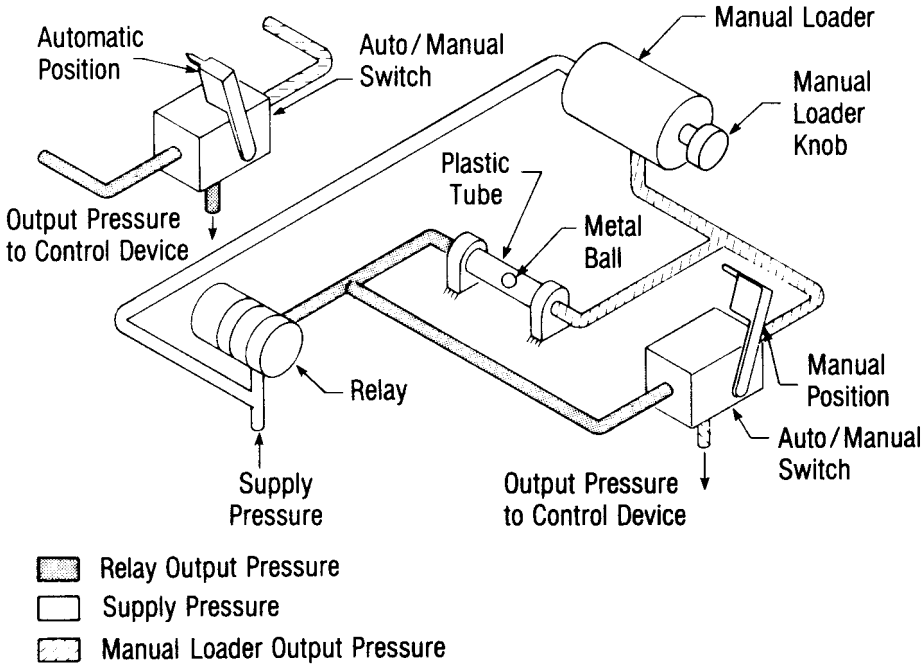

Figure 19: Schematic of Auto/Manual Option for Local Controller (Courtesy of Fisher Controls International, Inc.)

5.1.11.

Refer to Section 2.6 of the Chilton Process Control Handbook for more information.

5.2. Panel-Mounted Controllers

5.2.1. Pneumatic

1. Local controllers usually measure the process variable directly and do not need transmission. Controllers mounted in control rooms usually receive their process measurements indirectly through transmission. This allows measurement without piping hazardous fluids into the control room.

2. The function of various types of transmitters is covered in the tutorials for Pressure, Temperature, Level, and Flow, and thus shall not be included here.

3. Pneumatic transmission is usually 20 to 100 kPa (3 to 15 psig) signal. This signal represents the process variable linearly, or, in the case of flow, in proportion to the square root of the variable. The controller actually measures the air signal, but the scale is usually in the engineering units involved.

4. The most common electrical transmission signals are 4 to 20 mA. As with pneumatic signals, the current signal represents the process variable either linearly or in proportion to the square root. Current signals allow transmission over considerable distance without loss of accuracy caused by voltage drop. The signal is often converted to 1 to 5 V in the control room. This allows the receiver instruments to be wired in parallel so that loss of one receiver instrument in the loop shall not cause loss of the other receivers. Microprocessor-based transmitters that use digital transmission rather than current allow greater accuracy and resolution than analog transmitters. These are referred to as "smart" transmitters.

5.2.2. Pneumatic

1. Panel-mounted pneumatic controllers are functionally similar to local-pneumatic controllers, but they are constructed to install in indoor control panels. Figure 20 shows a shelf assembly of controllers for installation in a panel. Figure 3 in Section 3.2.1 shows a complete panel. Also, some additional features which are not often found in local controllers are available.

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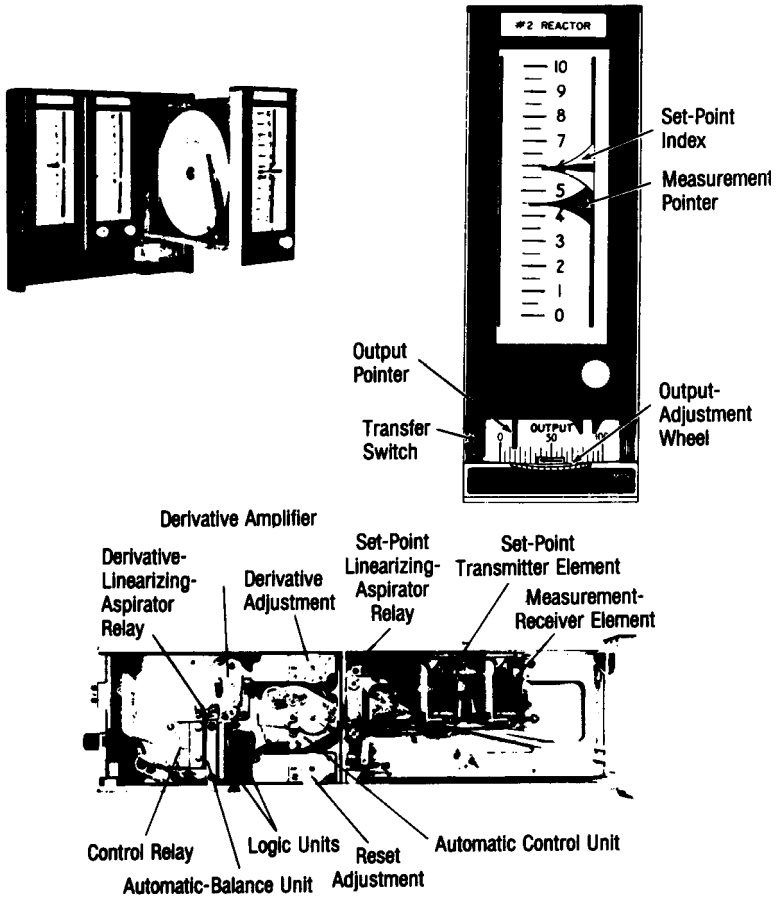

Figure 20: Photograph of a Panel-Mounted Pneumatic Controller (Courtesy of the Foxboro Co.)

2. The upper-right drawing of Figure 20 shows the front panel of a typical controller. A tag at the top indicates the process function of the controller. This is important because it shall be installed with a number of other similar controllers, and memorizing the function of each would be difficult. The set point index shows the set point. It is adjusted manually by the knob labeled "SET" just below the dial. Remote set point control is an option for most manufacturers' products. Often, two set point indexes will be installed, and there will be a remote/local set switch. The measurement pointer indicates the process variable, usually in engineering units, but the actual signal received is usually 20 to 100 kPa (3 to 15 psig) from a transmitter. The lower dial shows the controller output in percent. The other two pointers are memory pointers that the operator can set to indicate the normal range of output. The auto/manual transfer switch is on the left, and the manual output adjustment wheel is located under the lower dial.

3. The lower part of Figure 20 shows the side of the controller. The proportional-band adjustment is near the center of the unit on the

apparatus labeled "Automatic Control Unit". The derivative adjustment is just above (and the reset adjustment is just below) the proportional band adjustment. The measurement receiver element is at the right and is equivalent to the process variable sensing element. The control relay is located on the left.

4. There are also some additional elements not used in local controllers. The local set point transmitter element and a bellows that is part of the automatic control unit take the place of the mechanical linkage in the local controller. This allows a remote set point signal, or the local set point element, to be selected by a pneumatic switch. The derivative amplifier unit enables the controller to disable the derivative unit when the set point is changed and use it for process variable changes only, so that rapid set point changes do not cause process upsets. The logic units and automatic balance unit allow the operator to switch between automatic and manual without a balancing procedure as described previously (called bumpless transfer). The linearizing aspirator relays compensate for the non-linearity of the bellows elements.

5. These controllers are also discussed in detail in Section 2.6 of the Chilton Process Control Handbook.

5.2.3. Electronic

1. Figure 21 shows a typical analog electronic controller. It is very similar in appearance and function to the panel-mounted pneumatic controller. The components are very different, of course.

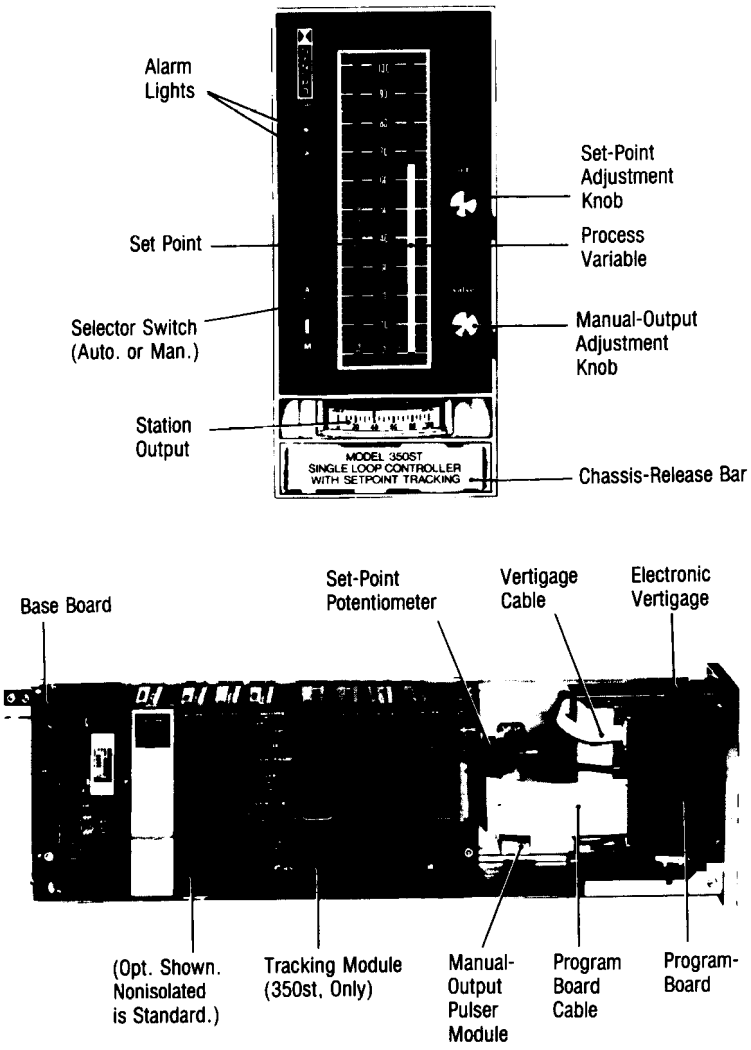

Figure 21: Photograph of Panel-Mounted Analog-Electronic Controller (Courtesy of Moore Products Co.)

2. The face of the controller is shown in the top part of Figure 21. Two vertical light tubes indicate the set point on the left and the process variable on the right. Several types of indicators are available from various manufacturers, including the light tubes shown, liquid crystal displays, and mechanical pointers. Alarm lights to indicate when the process variable is outside the desired range are shown on the upper left, and an auto/manual switch is shown on the lower left. The set point and manual output adjustment knobs are shown to the right of the scale. An output current meter is beneath the scale.

3. The side view in Figure 21 shows controller construction. A baseboard, vertigage (bar chart gauge) assembly, and program board make up the basic unit. Function modules are plugged into the baseboard to configure the controller with the desired control modes and options.

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Repairs can usually be made quickly by replacement of the suspect module. The proportional, integral, and derivative controls for this unit are on their respective modules. Other controllers shall have these controls grouped near the front, where the program board is located.

4. The most noteworthy difference is that the electronic controller uses a 4 to 20 mA signal in and out rather than a 20 to 100 kPa (3 to 15 psig) signal as for the pneumatic version. This requires a current-to-pneumatic transducer at the valve but allows the use of electrical cables rather than tubing for connection.

5. Electronic controllers are discussed in detail in Section 2.3 of the Chilton Process Control Handbook.

5.3. Digital Controllers

5.3.1.

Pneumatic analog controllers are limited to the mechanical characteristics of bellows, orifices, and mechanical linkages to develop control algorithms. Likewise, analog electronic controllers are limited to the characteristics of capacitors, resistors, inductors, and transistors to develop algorithms. While satisfactory process control is possible within the limitations of mechanical or electrical analog devices, sometimes a large number of devices is needed to achieve certain algorithms.

5.3.2.

A digital controller is a small microprocessor specially designed for process control. The control algorithm is developed mathematically by a computer program rather than by mechanical or electrical characteristics. Any control algorithm is possible, and non standard algorithms do not require an increased number of parts as would be required for analog techniques. Different controller characteristics for increasing and decreasing process variables or for ramping at start-up, different gains when near or far from set points, and rapid action when danger points are neared are only a few of the applications.

5.3.3.

Digital controller manufacturers have designed their products to minimize the retraining required for personnel familiar with analog techniques. The familiar proportional, integral, and derivative algorithms are available in almost all products. In addition, a number of other algorithms are available, depending on the product selected. The algorithms are pre-programmed so that the user selects the features desired and does not need to be a programmer. The details of how each of these functions is used is beyond the scope of this tutorial. The list is shown to illustrate that almost any

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control scheme that can be conceived can be implemented with digital control.

5.3.4.

Accuracy is better for digital controllers than for analog controllers because internal calculations are done digitally with computer precision. Most of the error remaining is from analog-to-digital input converters and digital-to-analog output converters. Also, digital controllers usually have digital readouts scaled in engineering units to minimize reading errors.

5.3.5.

Some digital controllers are designed to control only one loop and do very little more than the equivalent analog electronic controller. The advantages are that they are less expensive and more reliable because they have a smaller number of electronic components. They are also programmable.

5.3.6. Multi-loop Digital Controllers

1. Other digital controllers are designed to accept as many as eight inputs and develop as many as eight outputs. These controllers can replace eight analog single loop controllers and also can relate the inputs and outputs together to make a large multi-variable loop. Some examples of such loops are shown in Figure 22. These loops can be configured with analog controllers and computing devices, with each instrument bubble representing a separate device, or they can be done with only the transmitters, valves and one digital controller much more reliably and much less expensively. The purpose of showing these loops is to illustrate the capabilities of digital control rather than to show typical installations.

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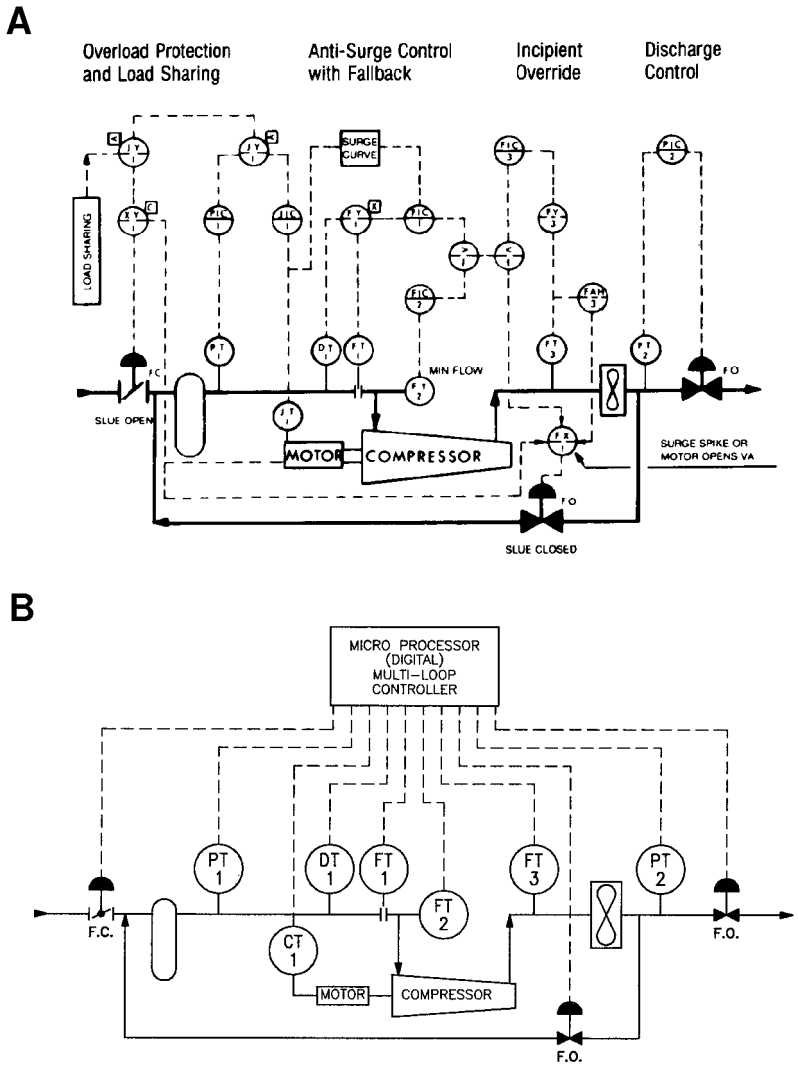

Figure 22: Examples of Digital-Controller Loops (Courtesy of Powell Process Systems, Inc.)

2. The loops shown in Figure 22A are a typical multiple-loop application where several controllers are used (PIC-1, PIC-2, PIC-3, FIC-1, FIC-2, FIC -3, and CIC-1).

3. Figure 22B shows the concept of the multi-loop digital controller accomplishing all control functions.

5.3.7.

Digital controllers are frequently the best choice for indoor electronic panels. Selecting the proper controller for the application is challenging because

there is no industry standard, and each manufacturer's product has unique advantages. Matching existing equipment is advantageous to reduce operator training. A good approach is to define the control problems and objectives as well as possible and then to ask a few sales representatives who serve the area where the equipment is to be installed to propose solutions. A session with a demonstration controller shall be very helpful in understanding how the controllers function and are programmed. Instructions that sound formidable when read are sometimes surprisingly clear when demonstrated using the actual controller.

5.4. Distributed Control Systems

Distributed Control Systems (DCS) are usually the best choice for larger facilities and/or where data acquisition and manipulation at a central facility is required. Refer to the tutorial EPT 05-T-09 on DCS for specifics.

6. Loop Configurations

6.1. Single-Variable Feedback Control

6.1.1.

A control loop that measures a process variable, applies a control algorithm, and develops a signal to control that same variable is a single-variable feedback-control loop. By far, the majority of process control loops fall into this category. Both local pneumatic loops and loops that use transmitters and control panels are included. Figure 23 shows examples of single-variable feedback loops as they would appear on a mechanical flow diagram.

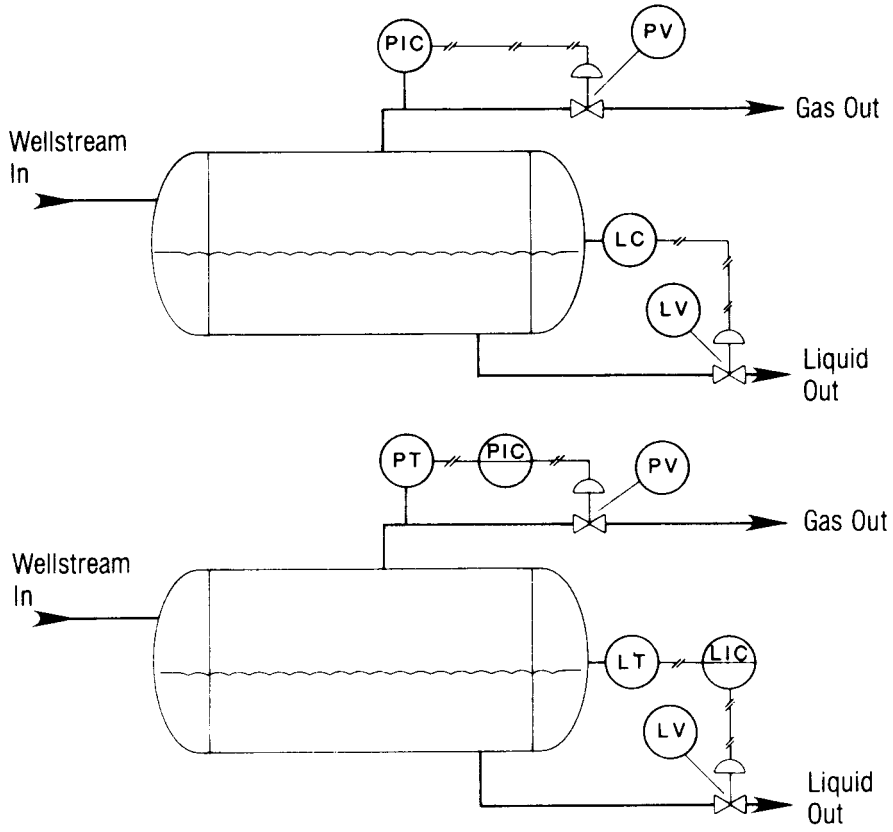

Figure 23: Examples of Single-Variable Feedback Control

6.1.2.

Proper selection of control modes for single loop controllers is essential to achieving the desired performance.

6.2. Feed-Forward Control

Feed-forward control is a configuration in which measurement of a process variable other than the one controlled is the primary input to the controller. Figure 24 shows a feed-forward control scheme for a wellstream heater. The flow rate and temperature of the wellstream are measured, and the amount of steam needed to heat it to the desired temperature is calculated by the computer. The computer controls the set point of the flow controller to allow the proper amount of steam. The temperature controller on the output of the exchanger gives feedback information to the computer to adjust the computation if required. Feed-forward control is seldom required for production facilities.

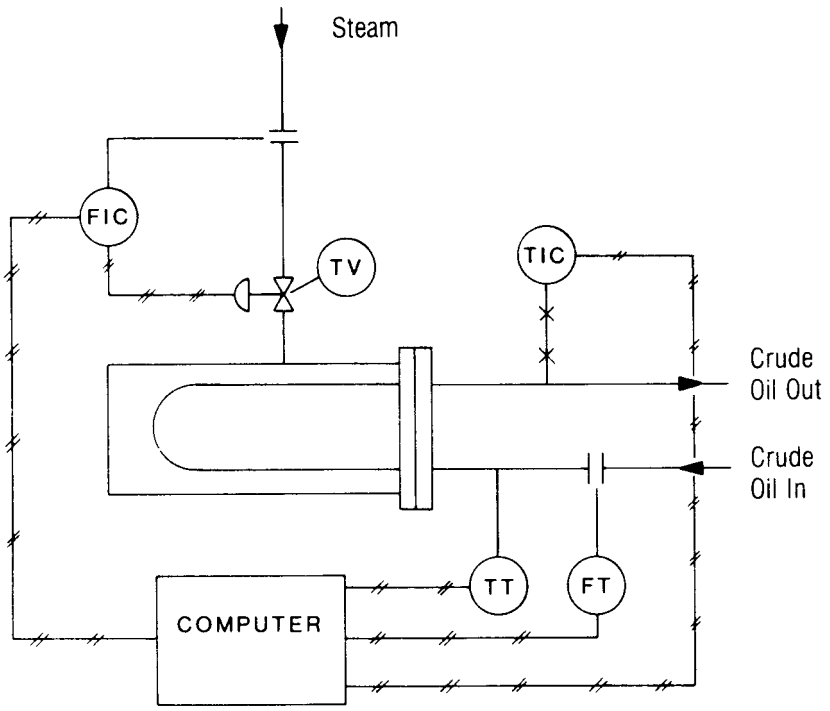

Figure 24: Feed-Forward Control Scheme for a Wellstream Heater

6.3. Cascade Control

Figure 25 shows an example of cascade control. The flow rate of steam is regulated by the primary controller, and its set point is determined by the temperature controller. With this scheme, the steam flow can be compensated for changes in pressure and other conditions in the steam system. The temperature in the tank shall change very slowly, so a temperature control alone will not compensate for changes in the steam system. By changing the set point of the flow controller, the temperature can be regulated and the steam flow can be held relatively constant. Cascade control is rarely needed in production facilities.

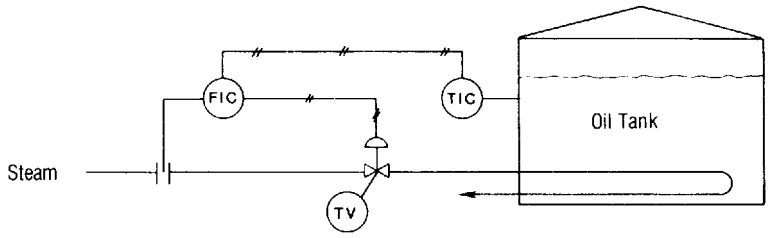

Figure 25: Example of Cascade Control

6.4. Multivariable Loops

Some control problems require inputs from two or more process variables and an algorithm other than the traditional proportional, integral, and derivative. The example most often encountered in production facilities is anti-surge control for centrifugal compressors. A typical anti-surge control loop is shown in Figure 26. This figure shows a minimum recycle control for a compressor, where inlet flow and differential pressure across the compressor are monitored to control the required recycle volume. Another example is boiler feed water control. These control problems can be handled with analog controllers and computing elements, but digital controllers are usually more effective and less expensive. These applications are best left to a specialist; thus, they shall not be discussed extensively in this document.

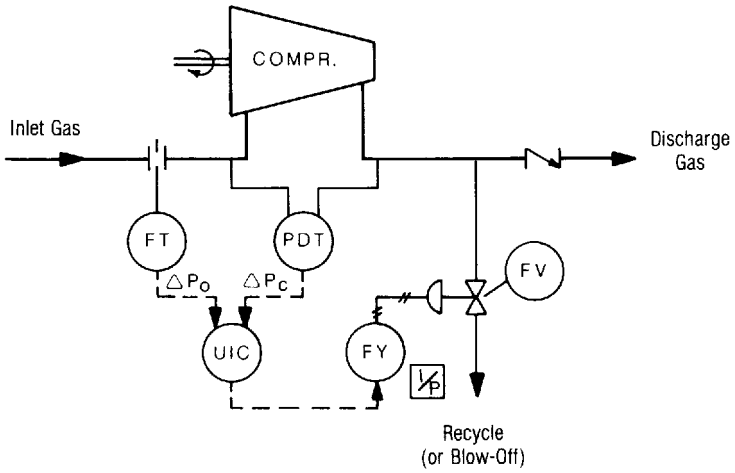

Figure 26: Schematic Showing Typical Antisurge Control Loop

7. Controller and Loop Tuning

7.1.

Classical control theory involves mathematically modeling the process by predicting capacities, time delays, and other parameters. Modeling real processes is very difficult and time consuming and is almost never cost effective. Fortunately, methods of tuning process controllers without accurately predicting these parameters have been developed.

7.2.

Controller manufacturers usually supply a recommended tuning method in their installation and start-up literature. One of the more popular methods for tuning controllers shall be described here.

7.3.

The ultimate method of tuning requires that the process be in operation. The settings in Table 2 are recommended for start-up. They will not give optimum control but shall keep the process stable enough for controller tuning. If oscillations occur, the proportional band of the offending controller shall be doubled.

Table 3: Recommended Settings for Control Tuning

Type of Control	Start-up Setting
Flow	Proportional band: 200 percent Integral: 2 repeat/min Derivative: Off
Liquid Pressure	Proportional band: 200 percent Integral: 2 repeat/min Derivative: Off
Gas Pressure	Proportional band: 50 percent Integral: 2 repeat/min Derivative: Off
Liquid Level	Proportional band: 50 percent Integral: 2 repeat/min Derivative: Off
Temperature	Proportional band: 100 percent Integral: 1 repeat/30 min Derivative: 8 min

7.4.

Choose the loop judged most critical or that which wanders about the set point the most. Tune the integral to minimum or off and the derivative to minimum or off if the controller has these functions.

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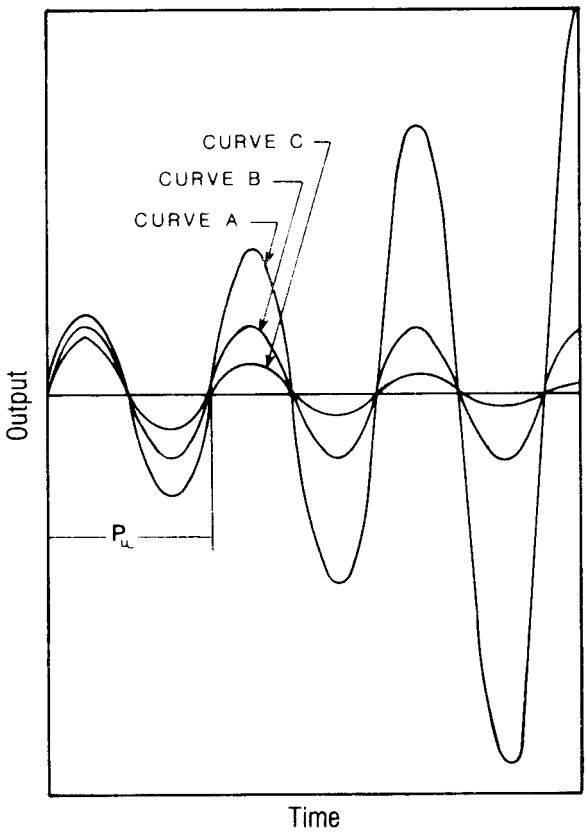
7.5.

With the controller in automatic control, alternately upset the process by moving the set point slightly then returning to the desired set point and reducing the proportional band until a steady oscillation similar to curve B of Figure 27 is achieved. If the process cycles increase in size as in curve A, increase the proportional band. If the process does not cycle, or the cycles damp out quickly, decrease the proportional band.



Curve A: Unstable
Curve B: Continuous Cycling, Read Ultimate Gain Period
Curve C: Stable

Figure 27: Proportional Band Responses in Different Conditions

7.6.

Note the proportional band setting and measure the cycle time. For a proportional-only controller, set the proportional band at twice the setting where oscillation was observed.

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7.7.

For a proportional-plus-integral controller, set the proportional band at 2.2 times the critical setting and the integral gain at 0.83 repeats/minute.

7.8.

For a proportional-plus-integral-plus-derivative controller, set the proportional band at 1.6 times the critical setting, the integral at 0.5 repeats/minute, and the derivative at 0.125 times the period. Instability shall result if the derivative is set much higher than 25 percent of the integral.

7.9.

Repeat this procedure with each of the control loops. This procedure is designed to tune the loop to damp out cycling after four repeats, which is generally considered optimum control. If cycling is undesirable, increasing the settings will reduce it at the expense of taking longer to tune out the offset (or allowing more offset for proportional-only).

7.10.

Some digital controllers automatically perform this or a similar self-tuning procedure when a self-tune button is pressed.

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Appendix A–Nomenclature

b = bias in percent output

D = derivative setting in minutes

e = error in percent of measured range

G = gain

Output = percent of controller output

PB = proportional band in percent of measured range

R = integral gain in repeats per minute

Programmable Logic Controllers

MP 32-P-14

April 1998

Scope

This Mobil Engineering Practice (MEP) describes general requirements for selection, application, design, programming and installation of simplex PLC systems supplied with vendor packaged control systems, applied to general purpose control of processes and equipment or used as Remote Telemetry Units (RTUs). Requirements for Triplicated Modular Programmable control systems (TMR) are specified elsewhere. HMI (Human Machine Interfaces) are outside the scope of this Practice.

Version 0

Table of Contents

Scope **1**

1. References **4**

1.1. MEPS–Mobil Engineering Practices 4

1.2. Mobil Data Sheets 4

1.3. API–American Petroleum Institute 4

1.4. IEC–International Electrotechnical Commission 4

1.5. IEEE–Institute of Electrical and Electronic Engineers 5

2. General **5**

2.1. Components 5

2.2. Enclosures 5

2.3. Control and Alarm Systems 6

3. Application **6**

3.1. Control Design 6

3.2. Installation 7

3.3. Enclosure Environment 7

4. CPU and Programming Package **7**

4.1. Backup 7

4.2. Memory 8

4.3. Clock Requirements 8

4.4. Processing Designs 8

4.5. On-line Programming 8

4.6. Password Security 8

5. Input and Output **8**

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5.1. Transient Surge Suppression 9
5.2. Discrete Outputs 9
5.3. Fusing 9
5.4. Fail-Safe Design 10
5.5. Remote I/O 10
5.6. Labels 10
5.7. Interposing Relays 10
5.8. Output Forcing 10
6. Power and Grounding 10
7. Serial Communication 11
8. Inspection, Testing and Documentation 12

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1. References

The following publications form a part of this Practice. Unless otherwise specified herein, use the latest edition.

1.1. MEPS–Mobil Engineering Practices

MP 32-P-05	Panels, Enclosures and Video Display Consoles
MP 32-P-13	Inst. Inspection, Testing, Calibration, Pre-Commissioning
MP 32-P-21	Wiring for Instrumentation and Digital Systems
MP 33-P-26	Electrical - Equipment Grounding and Bonding

1.2. Mobil Data Sheets

Mobil Data Sheets	Mobil Data Sheet Home Page
T3214C01	Programmable Logic Controllers - Customary Units
T3214M01	Programmable Logic Controllers - Metric Units
D3214C01	Programmable Logic Controllers - Documentation Requirements Sheet
I3214C01	Programmable Logic Controllers - Inspection and Testing Requirements Sheet

1.3. API–American Petroleum Institute

API RP 500	Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities First Edition (Supersedes RP 500A, RP 500B, RP 500C)

1.4. IEC–International Electrotechnical Commission

IEC 61000-4-3	Electromagnetic Compatibility (EMC) - Part 4: Testing and Measurement Techniques - Section 3: Radiated, Radio-Frequency, Electromagnetic Field Immunity Test

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1.5. IEEE–Institute of Electrical and Electronic Engineers

IEEE C62.64	Specifications for Surge Protectors Used in Low-Voltage Data, Communications, 1997

2. General

General requirements for the selection, application, design, programming and installation of simplex PLC systems supplied with vendor packaged control systems, applied to general purpose control of processes and equipment or used as Remote Telemetry Units (RTUs) shall be in accordance with requirements of this MEP, unless superceded by more stringent local regulations.

- Selection of a PLC manufacturer shall conform to the project-approved vendor list and shall be consistent for all PLC control systems used throughout the project. Consistency of manufacture and family/model types selected for a single project shall be ensured and any deviation shall require specific project approval.
- PLC designs shall provide control of a single piece of equipment or vendor package.

2.1. Components

- All PLC components shall be suitable for use from 0 to 60°C and from 0 to 95 percent relative humidity (non-condensing). The components shall be certified by UL, CSA, FM or IEC.
- All PLC components shall withstand vibrations of 1 G at frequencies less than 150 Hz and shock of 10 G based on 11 m/sec $^{1}/_{2}$ sine wave.
- EMI/RFI immunity ratings for all PLC components, including power supplies, shall meet or exceed IEC 61000-4-3 for heavy industrial environments. If the proposed manufacturer's PLC system does not meet these requirements, the supplier shall clearly point out all risks associated with EMI/RFI exposure and include the manufacturer's specifications to minimize exposure and risk.
- All PLC system components shall be designed and installed to allow a free flow of air sufficient to cool components without the need for forced ventilation.

2.2. Enclosures

- Enclosures shall be adequately sized to allow replacement and maintenance of PLC equipment and to provide adequate spacing for the termination of field wiring.

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Equipment shall not be mounted less than 4 inches from the enclosure sides, top or bottom. Sufficient space shall be provided to allow routing and bending of multicore instrument cables or power cables. Packaging and wiring shall be as defined in MP 32-P-05 and MP 32-P-21.

- In supplied enclosures, power and grounding wiring shall be kept separate from process control and instrumentation wiring and organized as much as possible. All wiring shall be installed in wire raceways (Panduit, for example). Control package design shall be organized and arranged for logical and efficient troubleshooting and maintenance.

2.3. Control and Alarm Systems

- Control and alarm circuits shall be designed fail-safe. In a normally energized circuit, any component failure or break in the control circuit shall induce an equipment fail-safe mode.
- When required by project specifications, First-Out alarm annunciation and sequence of events capabilities shall be provided.
- When required or specified on cause and effect drawings, local manual emergency shutdown pushbutton stations shall be hard-wired to disconnect and mechanically disconnect power to the PLC control system and associated controls. When power disconnection may create a hazard or potential equipment damage, specific project approval of shutdown design shall be required.

3. Application

- Simplex PLCs can be applied where vendor packaged equipment facilitates "off the shelf" designs, subject to prior project approval.
- Simplex PLCs can be applied where the size of the control system, the nature of the process or the equipment being controlled does not justify the added cost and reliability of redundant controls, subject to prior project approval.
- Simplex PLCs can be applied in SCADA system applications where low power consumption is not required or where RTUs and PLCs would otherwise coexist in the same physical location.

3.1. Control Design

PLC control designs are preferred over relay control panel designs in all but the smallest applications or where operating conditions cause MTTR to be appreciably shorter with relay panels.

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3.2. Installation

- PLC systems installed indoors, in areas not classified as Class I, Division 1 or 2, per API RP 500, shall be in NEMA 12 enclosures. Exceptions require specific project approval.
- PLC systems installed outdoors shall be in unclassified areas in NEMA 4X enclosures. A rain shelter protecting a paved, elevated area around outdoor PLC panels shall be provided to allow commissioning and maintenance during worst-case weather conditions.
- PLC systems shall not be installed in Class I, Division 1 areas.
- PLC systems shall not be installed in Class I, Division 2 areas unless all components are certified for use in Class I, Division 2 and prior project approval by Mobil has been granted. Designs using purging or pressurization of enclosures to meet area classification requirements require prior project approval.

3.3. Enclosure Environment

The enclosure's internal environment shall meet the required operating specifications for all PLC equipment housed in the enclosure. Potential exposure to heat, dust, humidity, vibration and corrosive gasses shall be evaluated and properly addressed in the package design, based on local conditions.

4. CPU and Programming Package

- CPUs shall process I/O, perform on-line diagnostics and alarm any abnormal CPU operation. A "watchdog" timer shall be incorporated into the CPU design. One-hundred-percent processor loading is defined as a worst-case scan period of 100 m/sec.
- One PLC programming package, including cables, shall be provided to Mobil for each type of PLC system provided. The program package shall include all software required to properly support the PLC system. Program packages shall operate in MS Windows 3.x or MS Windows NT environments. Program packages that require PC hardware or PC expansion cards shall not be used.

4.1. Backup

CPU program logic and all data registers shall be preserved during power failures. If battery backup is used to perform this function, a low battery alarm shall be provided and provisions shall be made for on-line replacement of the battery(s).

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4.2. Memory

CPU selection shall ensure that processor and memory loading, including data storage, shall not exceed 50 percent. This shall be demonstrated during the Factory Acceptance Test (FAT). If this specification is not met, at Mobil's discretion a larger CPU that does meet this specification shall be provided by the vendor at no cost to Mobil.

4.3. Clock Requirements

CPU design shall be millennium compliant. Access to the clock by program logic shall be provided. Functions required are year, month, day, hour, minute and second. The clock shall be accurate to within ± 1 minute per month.

4.4. Processing Designs

- The CPU shall provide all program logic and computational functions required to efficiently and effectively fit the application. Special consideration shall be given to the need for floating point computations and PID algorithms.
- Conventional ladder logic processing designs shall be used unless prior project approval has been obtained to implement other processing designs (such as function block programming).

4.5. On-line Programming

On-line programming capability shall be provided along with keyswitch and programming software security schemes that prevent unauthorized on-line programming capability. A Disabled Outputs control mode shall also be provided as well as a processor Halt mode.

4.6. Password Security

Program packages and CPUs shall be designed with password security features that are properly configured to ensure that only authorized personnel have access to the PLC program logic and data registers. All security features, security configuration and security management designs shall be documented and provided to Mobil in a separate restricted PLC system documentation distribution.

5. Input and Output

- I/O points shall be logically grouped and appropriately segregated between I/O modules to build in system flexibility.

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- I/O designs shall be modular with keyed quick-connect wiring terminations that allow replacement of modules without disturbing field wiring.
- I/O modules shall be provided with status LED's for each discrete I/O and module "health" status LED(s) for analog and specialized I/O.
- All discrete I/O shall be optically isolated and provide a minimum of 1500 V channel-to-chassis isolation. Ratings for isolated analog I/O and galvanically separate circuits shall be 300 V minimum channel-to-chassis and channel-to-channel.
- Use of I/O circuit designs above 24 VDC are discouraged and shall require specific project approval.
- All I/O shall be protected from inadvertent reverse polarity connection.
- All I/O shall be electrically isolated from the system's internal power supply.
- All I/O modules shall be designed to prevent inadvertent insertion into the wrong slot.
- Minimum design requirement for analog A/D converters is 12 bits.
- A minimum of 10 percent spare I/O shall be provided for each I/O type.

5.1. Transient Surge Suppression

- As a minimum, transient suppression that meets the requirements of IEEE C62.64 surge protectors shall be provided.
- In applications where lightning or switching transient exposure is severe, all analog I/O shall be provided with external transient surge suppression installed per manufacturer specifications. Response time of suppressors shall be less than 10 nanoseconds, clamping voltage shall be less than twice nominal rating and capacity shall be 2 kA minimum based on a standard IEEE 8 x 20 microsecond waveform.

5.2. Discrete Outputs

- The use of solid-state discrete outputs is prohibited, with the exception of driving panel-mounted pilot lights mounted within 10 ft of the I/O module. Isolated relay outputs shall be provided for all other discrete output requirements. Outputs that drive inductive loads shall be equipped with external "snubber circuits" if not designed into the output module. Interposing relays are an acceptable alternative.

5.3. Fusing

- All output circuits shall be individually fused with fuse-status indication. Exceptions can be made for isolated outputs that are part of a fused circuit external to the PLC panel and for non-isolated outputs that drive pilot lights located on the PLC control panel. In these cases, a common fuse per output module group shall be provided.

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- All input circuits shall be fuse-protected to minimize impact to the control system when an input circuit shorts. Individual fusing of each input is required if analysis of logical grouping of inputs is unclear. In no case shall a single fuse feed signals to more than one input module. A common fusing arrangement is used, for example, if all selector switches and pushbuttons mounted on a control panel door control a single piece of equipment or a single process.

5.4. Fail-Safe Design

Outputs that shut in equipment or fail-safe valves shall be designed fail-safe. Designs shall provide one-to-two duplex outputs for critical process or equipment controls so that either output can initiate the safe condition (shutdown).

5.5. Remote I/O

The use of "remote I/O" architectures is prohibited in areas exposed to lightning and switching transients. Exceptions can be made for I/O mounted on the same control panel with the CPU or where remote I/O is connected to the processor via fiber optic cabling.

5.6. Labels

All I/O modules shall be labeled to reflect addressing.

5.7. Interposing Relays

- Interposing relays shall be used where the application requires switching of AC circuits.
- Contact ratings of relay output modules shall be sufficient to switch loads. Where current capacity requirements exceed module ratings, interposing relays shall be used.

5.8. Output Forcing

Output forcing capabilities shall be provided along with security schemes to ensure that forcing can only be performed by authorized personnel.

6. Power and Grounding

- PLC power supplies shall be rated to accept facility standard voltage and frequency input for applications where the PLC is not required to perform control functions during an AC power

failure. In-line AC transient and surge protectors shall be provided to protect all PLC power supplies.

- PLC systems designed to operate during AC power failures shall be powered at 24 VDC with a nominal input capability of 19–30 VDC.
  - Battery chargers shall be sufficiently filtered to allow operation of the PLC system when batteries are removed for maintenance.
  - AC powered systems fed from UPS circuits may also be used to power PLCs for these applications, where proximity to existing UPS systems or other factors best fit the application and when specifically approved by Mobil.
- PLC systems shall be grounded per manufacturer recommendations and MP 33-P-26. Particular attention is required to ensure that proper grounding of all transient suppressors is achieved using the shortest possible straight path to facility ground.
- Circuit protection shall be properly sized and coordinated to protect equipment and prevent shutdown of the PLC system. This requirement also applies to DC circuits.
- PLC power supplies shall be designed to operate at less than 80 percent capacity. Derating due to extreme ambient temperatures or radiation heating shall be considered in the selection of power supplies.
- All power supplies and associated distribution of power throughout the PLC system shall meet or exceed IEC 61000-4-3 standards for RFI/EMI immunity for heavy industrial environments.

7. Serial Communication

- A minimum of two serial communications ports shall be provided. One port shall communicate using Modbus RTU slave protocol. One port shall be dedicated to programming connection and shall use RS-232 level signals. Alternate protocols and signals require specific project approval by Mobil.
- All serial communications lines shall be protected from lightning and switching transients using protective devices that meet or exceed IEEE C62.64 standards for surge protectors. Exceptions can be made for circuits that do not exit a control panel enclosure and for temporary, local connection of programming equipment. All proposed serial communications transient protection shall require specific project approval before an order is placed.
- High-speed proprietary communications networks shall be applied where serial bandwidth is insufficient to transfer data in large networked applications.

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8. Inspection, Testing and Documentation

- Documentation shall be provided as defined in the Mobil Data Sheets for this MEP. As a minimum, documentation shall be provided describing the operation and maintenance of the control system in both on-line and off-line modes. Documentation shall contain clear procedures, which highlight any risks to the controlled process or the integrity of the system.
- Documentation shall include detailed drawings of the complete system and shall include all I/O, power and grounding wiring and components.
- An interlock narrative description shall be provided to clearly explain program logic for inclusion into operating procedures. Calibration data, device configuration settings, time delay settings, etc. shall also be included.
- Program logic shall be listed with annotations sufficient to adequately describe program operation.
- A description of available system training shall be provided.
- A restricted distribution PLC security maintenance document shall be provided as described in Section 4.6 of this MEP.
- Inspection and testing shall be provided as defined in the Mobil Data Sheets for this MEP and as further defined in MP 32-P-13.
- Prior to FAT, the PLC control system shall be complete and fully tested by the vendor.
- Prior to FAT, drawings and documentation that detail terminations, wiring, equipment and module labels shall be completed.
- FAT test procedures and schedules shall be submitted for project approval a minimum of two weeks prior to FAT. The vendor shall record FAT test records and results. All necessary test and simulation equipment shall be provided by the vendor performing the test. Test records shall be distributed within two weeks of completion of FAT. Mobil reserves the right to witness all testing.
- Communications interface testing shall be performed as required in the package specifications.
- Any test failure shall be rectified at no cost to Mobil and re-tested until successful completion of the test is achieved, as determined by Mobil or Mobil's representative.

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Programmable Logic Controllers (PLC)

EPT 05-T-10

October 1992 Draft

Version 0

Table of Contents

1. Scope 3

2. References 3

2.1. MEPS–Mobil Engineering Practices 3

2.2. Mobil Tutorials 3

2.3. CHILTON–Chilton 3

2.4. NEMA–National Electrical Manufacturers Association 3

3. System Architecture 4

3.1. General 4

3.2. Programming and Man/Machine Interface 6

3.3. Central Processing Unit (CPU) 7

3.4. Memory Storage 8

3.5. I/O System 9

3.6. Power Supply 9

4. PLC Selection 9

4.1. Versatility 10

4.2. Flexibility 10

4.3. Expandability 10

4.4. Cost 10

4.5. System Definition 10

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1. Scope

This tutorial covers the design (architecture) and selection of Programmable Logic Controllers (PLC) for onshore and offshore production and processing facilities' control system applications. Fault-tolerant, redundant, microprocessor-based systems, although an integral part of the PLC concept, are not covered in this tutorial. Refer to the tutorial EPT 05-T-11 on Safety Shutdown Systems for information on these systems. Refer to the tutorial EPT 05-T-01 on Instrumentation Basics for definitions of terminology used in this tutorial.

2. References

The following Mobil guides and industry publications shall be considered a part of this EPT. Refer to the latest editions unless otherwise specified herein.

2.1. MEPS–Mobil Engineering Practices

MP 32-P-14	Programmable Logic Controllers

2.2. Mobil Tutorials

EPT 05-T-01	Instrumentation Project Basics
EPT 05-T-02	Controllers and Control Theory
EPT 05-T-11	Safety Shutdown Systems

2.3. CHILTON–Chilton

CHILTON	Instruments Engineer's Handbook (2 Volumes): Process Measurement and Process Control

2.4. NEMA–National Electrical Manufacturers Association

NEMA ICS 3	Industrial Control and Systems Factory Built Assemblies

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3. System Architecture

3.1. General

3.1.1.

A programmable logic controller (PLC), or simply programmable controller (PC), is a unified control system designed to provide both digital and continuous logic control functions. A PLC can function on its own or as a part of a distributed control system. Since PLCs operate with a digital format, interface or communications with computers is relatively simple. Since the PLC's original purpose was to replace large blocks of electro-mechanical relays, PLC programming (in the USA) is quite similar to the development of a standard relay ladder diagram. Some PC systems employ Boolean logic algebraic expressions.

3.1.2.

A basic difference between the way a relay system functions and the operation of a PLC is demonstrated by observing the two systems as a function of time. Any relay in a system can operate at any time depending on the status of the relay's individual controlling (input) element(s). A PLC, however, operates one rung at a time as it scans through the total control diagram. The PLC will not act on a change in an input element until it scans the affected rung of the ladder (program). The way in which the PLC scans the diagram is programmable. That is, the program can be set to check specific sections of the diagram regardless of the sequence of the diagram. The PLC has the additional advantage of being able to operate independent of the type of controlling element; i.e., normally open or normally closed contacts can be made to operate the same.

3.1.3.

The NEMA Standard 1CS3, Part 1CS3-304, defines a programmable controller as: "....a digitally operating electronic apparatus which uses a programmable memory for the internal storage of instructions for implementing specific functions, such as logic, sequencing, timing, counting, and arithmetic, to control through digital or analog input/output modules various types of machines or processes. A digital computer which is used to perform the functions of a programmable controller is considered to be within this scope. Excluded are drum and similar mechanical type sequencing controllers."

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3.1.4.

PLC capabilities continue to expand with the development of the computer industry in general. From the increase in capability come more specialized microprocessor-based control units called single- or multi-loop controllers. These devices are dedicated to continuous loop control functions. Such systems are commonly referred to as programmable controllers (PC). Refer to the tutorial EPT 05-T-02 on Controllers and Control Theory for specific details and application of these units. Figure 1 is a diagram of basic PLC architecture. The individual component functions are described in the following sections. PLCs and PCs are discussed in detail in Chapter 6 of the Chilton Process Control Handbook.

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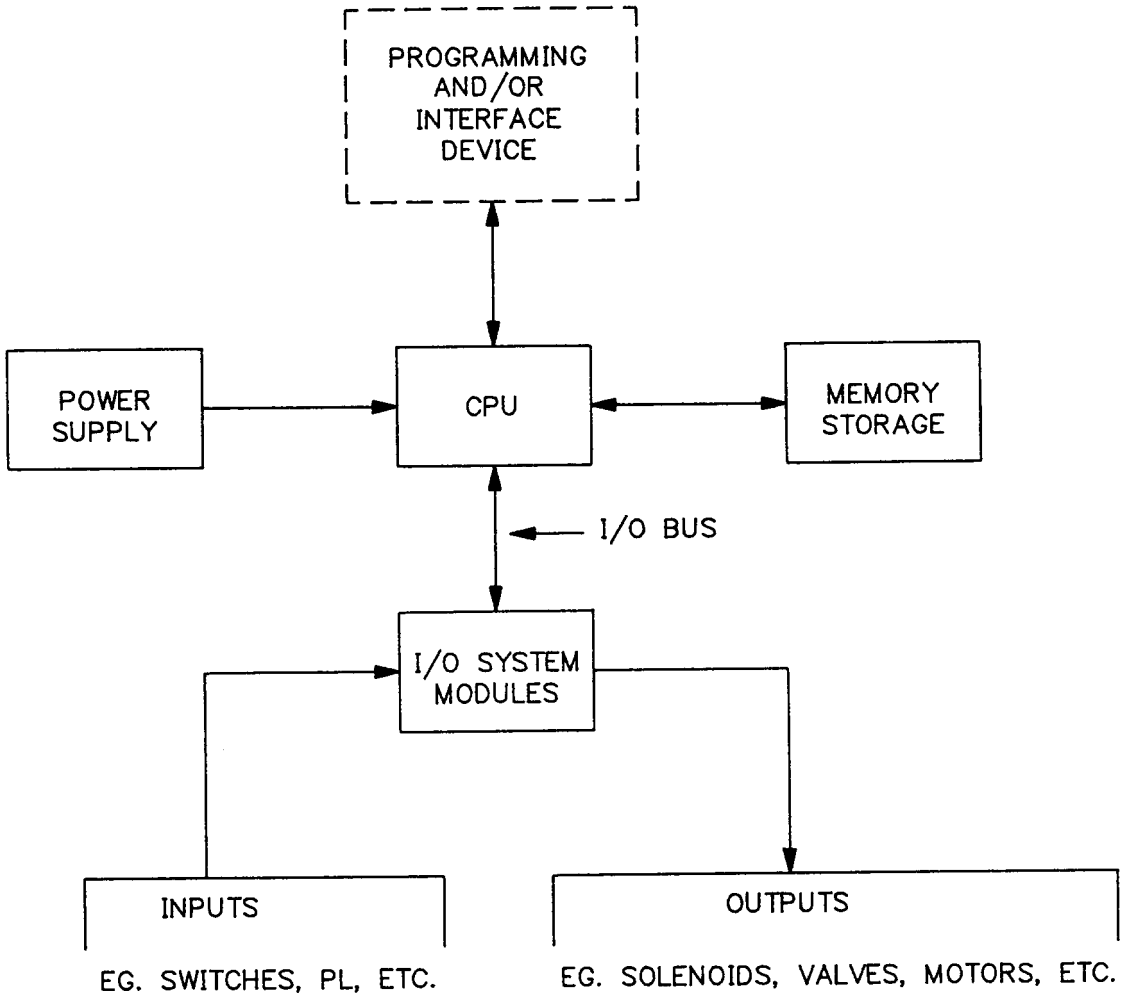

Figure 1: Basic PLC Architecture

3.2. Programming and Man/Machine Interface

3.2.1.

The configuration or programming of a PLC is accomplished by means of special keypad (hand-held terminal) or via a standard computer (desktop or laptop) using the specific manufacturer's configuration software. The software is generally a menu-driven program that includes instruction, documentation, and configuration options for the particular PLC. The following are the three basic types of programming formats used. At present, the ladder logic format is the primary format used in the USA (plain language function block format is gaining acceptance), while the block logic flow diagram format is predominant in Europe. The Boolean logic format is

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used in small specific task PLCs and some programmable controllers (typically those dedicated to CPU-based PID control, AGA calculations, and sequential control). Systems that use "smart" I/O for PID control and AGA calculations use either ladder or block logic programming format.

1. Ladder logic
2. Block logic flow diagram
3. Boolean logic

3.2.2.

Virtually all PLC configuration software includes provisions for both on-line and off-line programming, as well as options for program documentation and system hardware configuration. Only small, dedicated-function units lack this capability.

3.2.3.

The programming interface is normally the point of man/machine interface. This interface can take the form of LED lights and pushbuttons, LCD annunciation, hand-held terminal, or personal computer/operator workstation interface. Refer to Sections 6.1, 6.2, 6.3 and 6.4 of the Chilton Process Control Handbook for detailed information.

3.3. Central Processing Unit (CPU)

3.3.1.

The Central Processing Unit (CPU) performs the tasks defined by the PLC function. These tasks are program scanning, I/O bus traffic control, device communications, data handling, and system self-diagnostics. Central processing units of PLCs use either TTL (Transistor-Transistor Logic), CORE (ferrite core), CMOS (Complementary Metal Oxide Semiconductor), or microprocessor-based VLSI (Very Large Scale Integration). TTL provides faster scan times, while CORE requires no battery backup. CMOS is more compact and requires less power, whereas microprocessor-based systems are more powerful and more flexible. The various systems available employ trade-offs between speed and special features. Some systems employ a prioritized task sequence, or tasking, to enhance system scan time. Scan times can vary from about 1 msec ($^{1}/_{1000}$ sec) per 1 K (1024) words of logic to more than a hundred msec per 1 K of logic. Word size varies from 4 bits to 32 bits (most common are 8- and 16-bit words). Most PLCs support a timed interrupt routine to control scan sequencing. This means that the program can stop normal scanning at a specified point to check specified conditions before continuing.

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3.3.2.

The CPU operates in real time; that is, it functions in a continuous mode and responds instantly to changes, in accordance with program requirements. The system generally includes an internal clock and "watch-dog timer" to regulate the CPU and prevent functional errors from causing processor failures. The CPU shall perform its primary function of scanning the I/O for status, make sequential control decisions based on the control program, implement these decisions, and repeat this procedure within the allotted scan time. Refer to Section 6.4 of the Chilton Process Control Handbook for more details.

3.4. Memory Storage

3.4.1.

The program is stored in the memory of the PLC. Memory is separate from the CPU. The basic memory unit is a "word" which is made up of "bits". A bit is a single piece of data represented by one of two states: ON or OFF (ONE or ZERO). Generally, manufacturers refer to a word as 16 bits, a byte as 8 bits, or a nibble as 4 bits. Combinations of these bits yield messages referred to as words. Combinations of words produce control logic, which forms the program. Obviously, the larger the word, the more information contained within. Memory sizes vary from 256 words to 260 K words. Most basic PLCs have memory sizes in the 1 K to 48 K range.

3.4.2.

Memory storage can be volatile or nonvolatile. Volatile memory is erased if the power is removed, while nonvolatile is not. There are three basic types of memory storage: (1) Read-Only Memory (ROM), (2) Read/Write Memory (R/W), and (3) Random Access Memory (RAM). Read-only refers to memory that must be physically altered to change its contents. It is nonvolatile. Erasable or programmed ROM is referred to as programmable ROM or PROM. There are two basic types of PROM: (1) UV-PROM, which are erased by exposing the top of the chip to ultraviolet light and can be reprogrammed by burning in a new program; and (2) EPROM or EEPROM, which are nonvolatile but are electrically alterable. Both allow on-board re-burning of a program, and the EEPROM can be updated without physical alteration. Read/Write memory can be updated without physical change and can be volatile or nonvolatile. R/W memory is normally magnetic core and is used in larger PLC units. RAM memory uses integrated circuits. RAM is a read/write memory but is always volatile. CMOS is an economical, extremely compact read/write memory that requires some form of battery backup for nonvolatile application. Refer to Section 6.4 of the Chilton Process Control Handbook for more details.

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3.5. I/O System

3.5.1.

The I/O system is generally modular. That is, it includes modules that contain multiple input and/or output points. These modules can have 1, 2, 4, 8, 16, or 32 points, depending on the specific system/manufacturer. The I/O bus structure is actually a high-speed multiplexer that carries the information back and forth between the I/O modules and the CPU. The Input Modules are also signal conditioning/isolating devices that take the real world signals and provide the CPU with real-time variable status. Input signals can be either on/off (discrete) or continuously variable (analog) signals. Discrete signals are, for example, the status of switch contacts or pushbuttons, etc. Discrete signals are normally at 24 VDC, 120 VAC (60 Hz), or 230 VAC (50 Hz). Analog inputs are normally 4 to 20 mA, 0 to 5 VDC, or 0 to 10 VAC.

3.5.2.

The output module takes the CPU's instructions and converts them to the desired real-world status. Outputs are normally the same signal types as those for inputs. I/O Modules typically use some form of optical isolation between the real-world signals and the CPU data bus to protect the processor from external faults. Refer to Section 6.4 of the Chilton Process Control Handbook for more details.

3.6. Power Supply

The power supply provides power for the CPU, the memory, and the I/O logic signals, along with power for I/O loops and other peripheral devices as required. The supply can be integral with the system or mounted separately. It provides isolation and protection of the solid state system from the main power supply source. It also provides heat dissipation that is necessary to allow PLC applications in high ambient conditions. Standard supply voltages are 120/240V at 60/50 Hz with the actual CPU and system operating at 24 VDC. Refer to Section 6.4 of the Chilton Process Control Handbook for more details.

4. PLC Selection

A PLC is capable of sequential logic control, loop control, distributed process control, mathematical manipulation, and data acquisition and storage. PLCs are normally selected based on their versatility, flexibility, expandability, compatibility, and cost. Before a system can be selected, it shall be defined clearly.

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4.1. Versatility

As noted above, virtually all PLCs are capable of continual operation of pre- programmed logic, either discrete or analog. PLCs can also provide analytical capabilities required in control of dynamic systems (PID loop control, etc.).This capability simplifies the application of PLCs in production and/or processing facilities in which the control system requirements are normally some form of or combination of basic batch control functions. Batch control in this context is controlling a system or unit as an independent part of the total control system.

4.2. Flexibility

Due to the multi-function capabilities of a PLC, its control program is easily modified to meet changes or system optimizations such as those commonly discovered during facility start-ups. A PLC is a user-friendly control system due to its digital operating format and self-diagnostic capabilities.

4.3. Expandability

In general, a PLC can be expanded with minimal cost and system revisions. Some systems can be virtually doubled in size with practically no downtime of existing control functions. In some cases, this requires only a system configuration upgrade (downloading an updated program that has been prepared and tested off-line). Obviously, significant expansion of a system requires compatible changes in peripheral equipment and devices.

4.4. Cost

The original impetus behind the development of the PLC was to produce a sequential control system at a lower cost than conventional relay logic systems. Accomplishing this has produced a system with, for all practical purposes, infinitely more capability and flexibility at a significantly lower cost. Since these systems require configuration (programming), the initial cost of a small system can be higher than that of a relay system. As the system size increases and additional functions (such as PID control) are added, however, the PLC gains a significant cost advantage.

4.5. System Definition

Defining system requirements is usually accomplished by answering the following questions:

1. What are the control requirements?
2. What plans are there for future expansions or changes in control philosophy?
3. What are the data acquisition requirements?

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4. What are the operator and peripheral interface requirements?
5. What type of PLC is currently in use in this or related facilities?

4.5.1.

Control requirements are summarized into an I/O list that includes all input/output required and generally consists of:

Discrete-In	24 VDC
Discrete-In	120 VAC or 240 VAC
Discrete-Out	24 VDC
Discrete-Out	120 VAC or 240 VAC
Analog-In	mA or Volts
Analog-Out	mA or Volts
High Speed Counter-In	Frequency above 300 Hz
Low Speed Counter-In	Frequency below 300 Hz

4.5.2.

Every effort shall be made to assure that the selected equipment is readily expandable to accommodate future needs. This consideration can affect not only the size of the PLC but also the type of PLC and the spare capacity needed. Spare capacity shall always include 10 percent I/O to allow for configuration changes generated during start-up and debugging.

4.5.3.

Data acquisition requirements, manipulation, logging, and report functions shall be considered. Typical examples are as follows. Such requirements directly influence the type of system selected due to their impact on CPU capability and memory storage capacity.

1. Well Test logging.
2. Metering Data logging.
3. Shift, Daily, and Monthly report generation.
4. Alarm logging and reporting requirements.

4.5.4.

Operator and peripheral device interface requirements sometimes dictate the type and size of system to be considered. Nevertheless, interface requirements can also impact system selection based on communications requirements (e.g., will the system be connected to a central operator work-station, host computer, printer, or specialized analyzer equipment, or will it function as a component in a distributed control system or as an RTU?).

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4.5.5.

Compatibility with existing PLC systems is a must to minimize spare parts and to reduce network interface problems (where applicable). Using systems from the same manufacturer also reduces training and software requirements.

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Distributed Control Systems (DCS)

EPT 05-T-09

October 1992 Draft

Version 0

Table of Contents

1. Scope 4

2. References 4

2.1. MEPS–Mobil Engineering Practices 4

2.2. Mobil Tutorials 4

2.3. ISA–Instrument Society of America 4

2.4. CHILTON–Chilton 4

3. General 5

3.1. General Discussion 5

3.2. Concept and Development 7

3.3. Application 8

4. System Architecture 10

4.1. Controllers 10

4.2. I/O Modules 10

4.3. Data Highway 10

4.4. Gateways 11

4.5. Man-Machine Interface 11

5. System Configuration 11

6. System Selection 11

6.1. 11

6.2. 12

6.3. 12

7. Project Management 12

7.1. 12

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7.2. 12

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1. Scope

This tutorial covers the "DCS" concept and its development, system architecture, configuration, and selection for application in onshore and offshore production/processing facilities. Vendor project controls for large systems are also discussed. Refer to the tutorial EPT 05-T-01 on Instrumentation Basics for definitions of terminology used in this tutorial.

2. References

The following Mobil guides and industry publications shall be considered a part of this EPT. Refer to the latest editions unless otherwise specified herein.

2.1. MEPS–Mobil Engineering Practices

MP 32-P-16	Distributed Control Systems

2.2. Mobil Tutorials

EPT 05-T-01	Instrumentation Project Basics

2.3. ISA–Instrument Society of America

ISA S5.1	Instrumentation Symbols and Identification R(1992)
ISA S5.3	Graphic Symbols for Distributed Control/ Shared Display Instrumentation, Logic and Computer Systems
ISA S5.5	Graphic Symbols for Process Displays
ISA S51.1	Process Instrumentation Terminology R(1993)
ISA RP55.1	(WITHDRAWN) Hardware Testing of Digital Process Computers R(1983)

2.4. CHILTON–Chilton

CHILTON	Instruments Engineer's Handbook (2 Volumes): Process Measurement and Process Control

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3. General

3.1. General Discussion

3.1.1.

A distributed process control system, as the name implies, is an automated system that employs unit control functions that are interconnected in some manner to provide data acquisition and man-machine interface (usually at a central control room) for the efficient operation of a facility. A typical distributed process control system, as shown in Figure 1, includes individual unit control systems/components that are interconnected to a central computer which is equipped with a sequential control and data acquisition (SCADA) software system used to provide data acquisition and operator interface for facility control.

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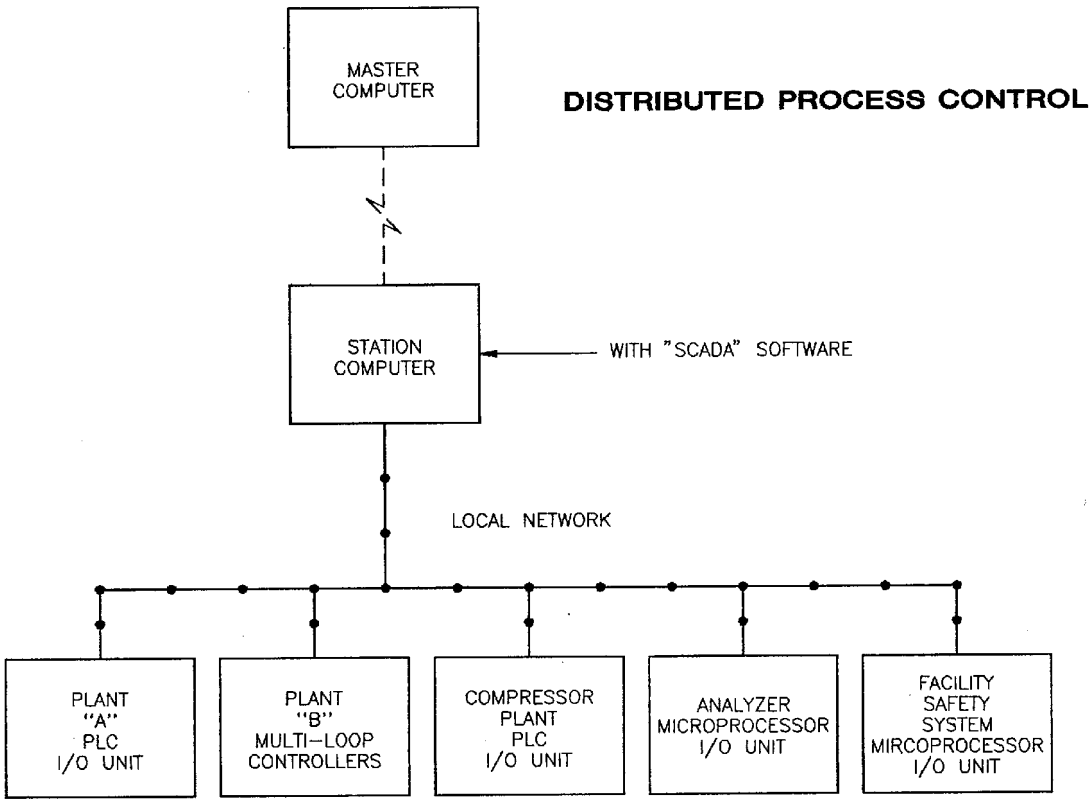

Figure 1: Distributed Process Control

3.1.2.

The concept of unit control responsibility within an overall control system has been used in the development of a unitized control system known simply as a "Distributed Control System" (DCS). A typical "DCS" is illustrated in Figure 2. While the distributed system shown in Figure 1 depends on various unit control systems, the typical DCS provides unit control systems on an individual control loop basis; thus, drastically improving flexibility. Another characteristic of a DCS is that each control loop is normally provided with an automatic switch over redundant loop controller processes, greatly improving system reliability. The "DCS" is the product of a single manufacturer and includes all operational and configuration software. Refer to Section 7 of the Chilton Process Control Handbook for a detailed discussion on computer and distributed control.

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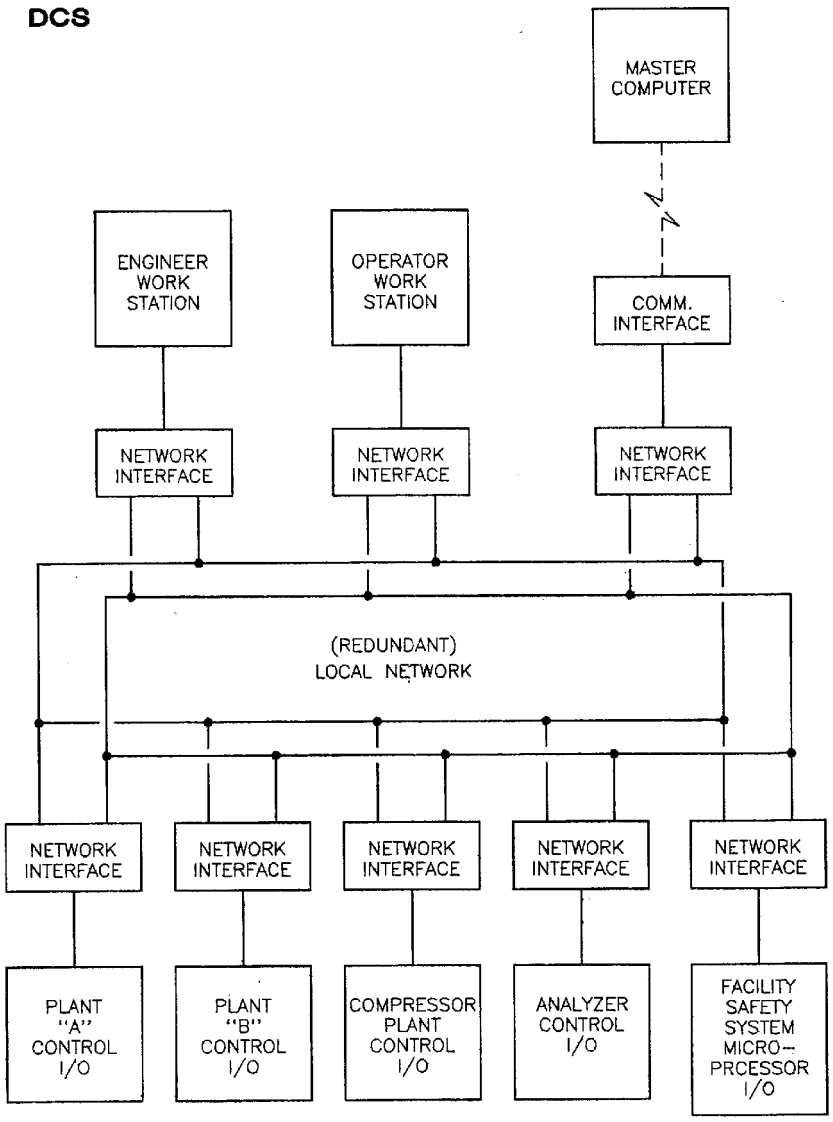

Figure 2: Typical DCS System

3.2. Concept and Development

3.2.1.

The development of computers and the application of microprocessors to process loop control has precipitated the design and manufacture of a unitized control system known as “DCS”. As noted above, these system designs are based on the concept of distributed control, and they employ microprocessor-based loop controllers to provide a highly versatile and reliable control system. A DCS incorporates not only the features of multi-

loop controllers, but also the digital capabilities of a PLC. The design and purpose of a DCS is to provide a control system that is, to the maximum extent possible, free from the consequences of single point failure. That is, when a control loop processor or I/O module malfunctions, the system automatically switches to the backup (redundant) processor or I/O module; this is accomplished without affecting the controller element. This concept also provides the ability for on-line configuration/ reconfiguration of individual control loops.

3.2.2.

All distributed control systems are modular in design, and each manufacturer tends to refer to various modules with unique names or acronyms. However, the generic identification of a basic system's components is as follows:

1. The man-machine interface.
2. The data highway.
3. The controller and I/O unit(s).
4. Communications gateways.

3.2.3.

The man-machine interface refers to the operator's controls and the engineer's or technician's workstation. The data highway generally refers to the local area network that interconnects all DCS modules and serves as the system data transfer path. The controller and I/0 unit or units are the field interface and control modules. The communications gateways are the modules that allow interface of foreign devices and systems into the DCS data transfer network. DCS size can be viewed/stated on a loop basis, where a loop is defined as the lowest level of control or indication. The minimum size controller and I/O modules vary from eight to twenty loops, depending on the manufacturer.

3.3. Application

The basic question to answer in the application of a DCS is the same question for any control system: “What type of system do I need?” Before this question can be answered, the following basic questions shall be addressed:

1. Will the facility be controlled from a central control room or location? If the answer is yes, then proceed; otherwise, consider other types of systems.
2. What are the control requirements? Will controls include ON/OFF, PID, or a combination of both, and how many loops will there be? Control requirements can be summarized into a list that includes the number of regulatory controllers (PID), the number of ON/OFF controllers, and the I/O list. Will the facility be controlled from a

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central control room or location? If the answer is yes, then proceed; otherwise, consider other types of systems.

3. What are any future plans for expansion or possible changes in system control philosophy? Every effort shall be made to assure selection of system architecture that is readily expandable to accommodate future needs. This includes a spare capacity allowance of 10 percent I/O for start-up debugging and changes.

4. What specific data acquisition, manipulation, logging, and reporting functions are required? This question encompasses such things as the following:

   a) Well test logging.

   b) Metering data logging.

   c) Metering/control trending.

   b) Shift, daily, and/or monthly reports.

5. What are the alarm logging and reporting requirements? An important aspect of evaluating a system is the way it handles system and process (input) alarms. Generally, all alarm logging and reporting must be independent of control operations and totally free of interference. Alarms shall have priority during data transmission.

6. How is the system database to be handled? Normally, a distributed database format is required, with each highway node originating the following. This means that the data highway is the real-time database window so that every system node has instantaneous access to all data it may require.

   a) Engineering unit value data.

   b) Discrete status.

   c) Process point and system alarms.

   d) Diagnostic information.

7. Will on-line configuration capability be required? On-line configuration provides the ability to change control strategies without taking the controller (loop) off-line (loop shutdown is not required). Typically, this is done using an engineering workstation on the system while normal operations continue.

8. What are the engineering and operator interface requirements? Generally, an engineering workstation is used for initial system configuration, on-line changes/debugging, and system/process analysis/trending. The operator's interface (node) is just that. It functions as the man-machine interface for facility control. The facility/process complexity and particular Digital Equipment Corporation (DEC) multi-tasking capabilities dictate the number of operator stations required.

9. What are the requirements for peripheral equipment/devices? The selected system shall have the interface capability to communicate with equipment of other manufacture that might be required as a part of the completed control system. This includes such items as PLCs, host computers, analyzers, etc. Any such items planned shall be included for the DCS vendor to assure compatibility with each system/device protocol.

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10. What are the project facility's physical distribution requirements? Knowledge of the proposed plant layout and location of control and data acquisition points influence the way the required system is packaged, especially controllers and I/O units. In other words, the system hardware architecture shall be specified.

4. System Architecture

4.1. Controllers

DCS controllers provide the following three basic control strategies. Generally, the system configuration software includes a selectable menu of typical control algorithms. The user selects the desired algorithm and, through a system of menus, configures each controller to fit the project control requirements.

4.1.1. Continuous Control

This is the most common type of control. It refers to basic (PID) type loop control.

4.1.2. ON/OFF or Sequencing

This is discrete-type control commonly used in PLCs, etc.

4.1.3. Advanced Control

Advanced control is the application of integrated batch or unit controls to establish a system control function; basically, this means establishing a multi-loop controller that simultaneously controls several related control loops.

4.2. I/O Modules

The input/output modules are interfaces of field devices with the DCS. These modules provide the isolation between the system data processing and the field device. They generally include analog-to-digital (A/D) and digital-to-analog (D/A) signal conditioning required for device interface.

4.3. Data Highway

The data highway is the communication device that provides the high speed transfer of data between the components that make up a DCS. Each primary device/module is a node on the highway. The communications system provides the encoding of the data, using a standard protocol. Several protocols are used in the industry; however, the most common

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is “High-Level Data Link Control” (HDLC). Communications between nodes is usually handled by the following. Refer to Section 7.4 of the Chilton Process Control Handbook for details on these communications techniques.

1. A traffic director.
2. A token-transfer.
3. Carrier sense multiple access.
4. Broadcast shared memory.

4.4. Gateways

All distributed control systems provide the means to communicate to foreign devices such as PLCs, analyzers, printers, etc. Each gateway operates as a node on the data highway and provides the means to match the foreign device protocol to the DCS communications system.

4.5. Man-Machine Interface

Man-machine interface refers to the operators' and/or engineers' consoles. The units contain the software used to configure the system and generate configured graphic displays. The engineers' console also contains the software required for system analysis, trending, etc.

5. System Configuration

System configuration consists of programming the DCS to do the control functions, store desired data, and generate required reports. System configuration also includes programming each controller, developing operator display graphics, and setting alarm system priorities.

6. System Selection

6.1.

System selection includes all the steps discussed in Section 3.2 concerning application of a DCS to facility operation plus the following considerations.

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6.2.

Selection of a DCS requires the same consideration as any other major process component. It is the control system, and compatibility with existing systems and field devices is prerequisite. Manufacturers do vary in both software and hardware architecture. Selection shall include assurance that the hardware architecture, especially in the packaging of controller files and I/O modules, is compatible with the project requirements. The configuration and operating software shall provide a user-friendly environment to effect the efficient operation of the facility.

6.3.

The selected system shall have the ability to be expanded without interrupting operations. This includes the addition or deletion of system nodes.

7. Project Management

7.1.

DCS system size is generally related to control loop quantity. System cost can also be related to loop quantity. A typical DCS cost is on the order of $1800 (U.S.) per loop, and the smallest economical system is generally twenty loops.

7.2.

Although small distributed control systems (fewer than 50 loops) are economical and may not heavily impact a project schedule, most DCS applications are with much larger systems. These larger systems have a significant impact on project costs (a system with 450 loops costs approximately $800,000 U.S.) and the project schedule. This circumstance requires that the selected vendor shall proceed with the system supply in an efficient and timely manner. This can be accomplished only with good project management on the part of the vendor and the instrument engineer.

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Control Centers

MP 32-P-08

July 1998

Scope

This Mobil Engineering Practice (MEP) describes the design of a control center, the facilities required in the control center for efficient and safe operation and states specific requirements for equipment layout and wiring.

This Practice covers large control centers for control of multiple process units as well as single purpose units found in offshore and onshore production units. Architectural design and construction details are outside the scope of this Practice.

Version 0

Table of Contents

Scope **1**

1. References **3**

1.1. MEPS–Mobil Engineering Practices 3

1.2. Mobil Data Sheets 3

1.3. Mobil Tutorials 3

1.4. API–American Petroleum Institute 4

1.5. ISA–Instrument Society of America 4

1.6. NFPA–National Fire Protection Association 4

2. Building Design **4**

2.1. Location 4

2.2. Size and Layout 5

2.3. Control Room 9

2.4. Rack Room 10

2.5. Computer Room 11

2.6. Permit Room 11

2.7. UPS Room 11

2.8. Battery Room 12

3. Building Infrastructure **12**

3.1. Environment and Security 12

3.2. Wiring 14

3.3. Communications 14

3.4. Grounding 14

3.5. Electric Power 15

3.6. Raised Floors 15

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1. References

The following publications form a part of this Practice. Unless otherwise specified herein, use the latest edition.

1.1. MEPS–Mobil Engineering Practices

MP 32-P-21	Wiring for Instrumentation and Digital Systems
MP 33-P-15	Electrical - Stationary Batteries & Chargers
MP 33-P-16	Electrical - AC Uninterruptible Power Supply (UPS) System
MP 33-P-23	Electrical - Raceway & Cable Tray Installations
MP 33-P-26	Electrical - Equipment Grounding and Bonding
MP 33-P-32	Electrical - Intrafacility Communication Systems and Alarm Systems
MP 41-P-30	Heating, Ventilation, Air Conditioning (HVAC) Systems
MP 70-P-01	Loss Prevention - Facilities
MP 70-P-09	Fire and Gas Detection

1.2. Mobil Data Sheets

Mobil Data Sheets	Mobil Data Sheet Home Page
D3208C01	Control Centers - Documentation Requirements Sheet
I3208C01	Control Centers - Inspection & Testing Requirements Sheet
T3208C01	Control Centers - Customary Units
T3208C02	Control Centers - Pressure Control Valves & Regulators - Customary Units
T3208C03	Control Centers - Self-Actuated Temperature Regulator - Customary Units
T3208M01	Control Centers - Metric Units
T3208M02	Control Centers - Pressure Control Valves & Regulators - Metric Units
T3208M03	Control Centers - Self-Actuated Temperature Regulator - Metric Units

1.3. Mobil Tutorials

EPT 06-T-06	Electrical Power Distribution Systems-Industrial & Large Commercial

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1.4. API–American Petroleum Institute

API RP 500	Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities First Edition (Supersedes RP 500A, RP 500B, RP 500C)

1.5. ISA–Instrument Society of America

ISA S71.01	Environmental Conditions for Process Measurement and Control Systems: Temperature and Humidity
ISA S71.04	Environmental Conditions for Process Measurement and Control Systems: Airborne Contaminants

1.6. NFPA–National Fire Protection Association

NFPA 70	National Electrical Code 1996 Edition Errata #1; Tentative Interim Amendment 1996

2. Building Design

The design of a control center, the facilities required in the control center for efficient and safe operation and requirements for equipment layout and wiring shall be in accordance with requirements of this MEP, unless superceded by more stringent local regulations.

2.1. Location

Control centers shall be located a minimum of 150 m (500 ft) from any blast source whenever plant layout permits. Control centers and any building containing control equipment closer than 150 m (500 ft) from a blast source shall be of blast-resistant construction.

Where there is little overall cost difference between construction of a control center of blast-resistant construction near blast sources and nonblast-resistant construction located away from blast sources, the site away from blast sources is preferred.

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- The design of the site near blast sources is based on certain assumptions (although conservative, are still assumptions) since the actual intensity of a blast cannot be accurately predicted. For this reason alone, it is better to avoid blast-resistant construction by choosing a safe location.
- Should this be impractical, however, the rooms in the control center that require blast-resistant construction include the control room, equipment room, uninterruptible power supply (UPS) room and battery room.

2.2. Size and Layout

Control center size depends on the size and complexity of the plant under control. The basic rule for design is that all process operations and only process operations shall take place in the control center.

2.2.1. Large Control Centers

Large control centers shall have a very strict separation of functions by providing a room for each function. Figure 1 is a typical control center floor plan for a large refinery where the only function in the control room is plant operations.

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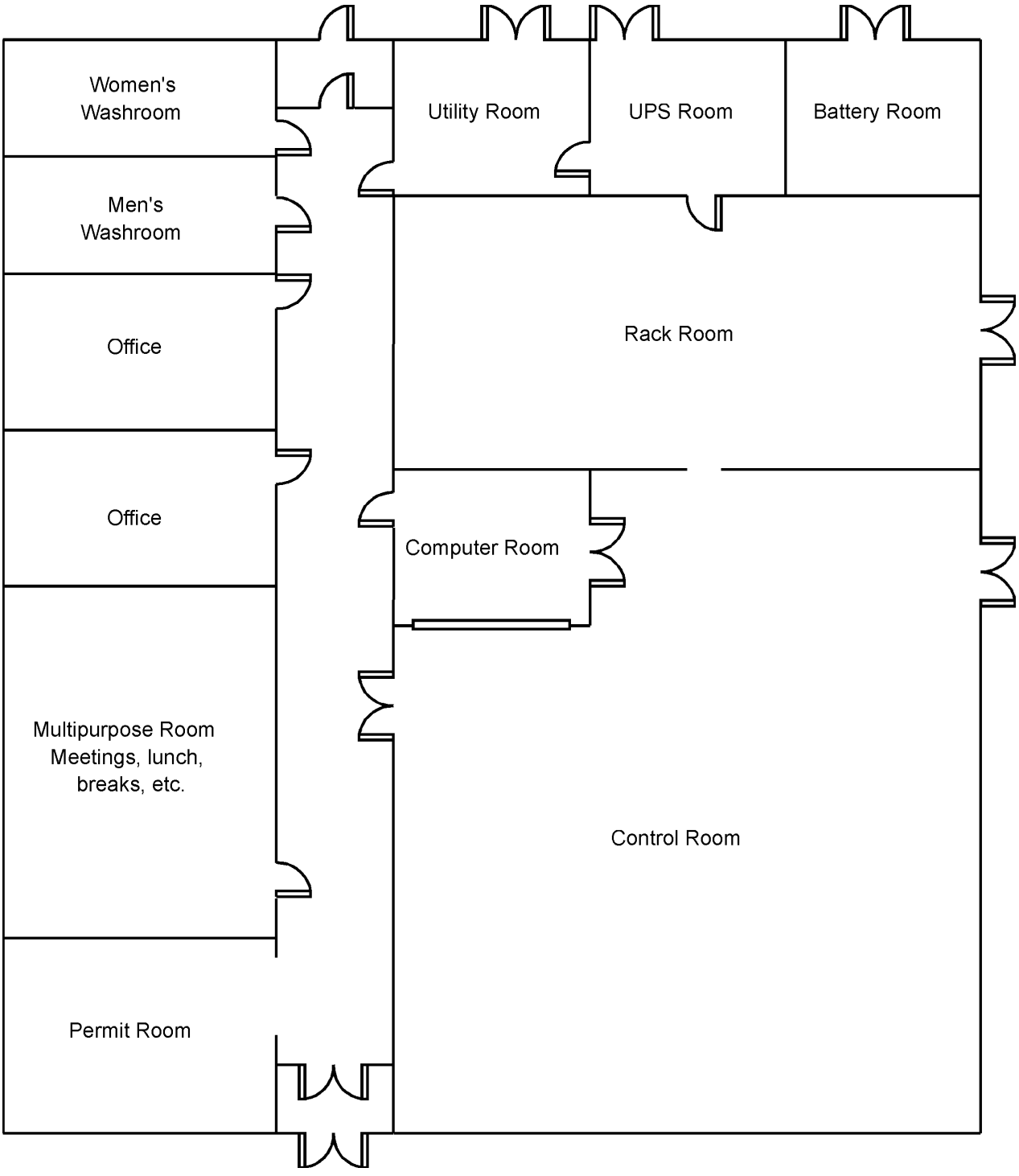

Figure 1: Large Control Center Plan

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2.2.2. Small Control Centers

Smaller control centers, as for offshore platforms, may have closely associated functions in the same room. Figures 2 and 3 illustrate small control centers (onshore and offshore) where the Control Room is in the same room as the racks.

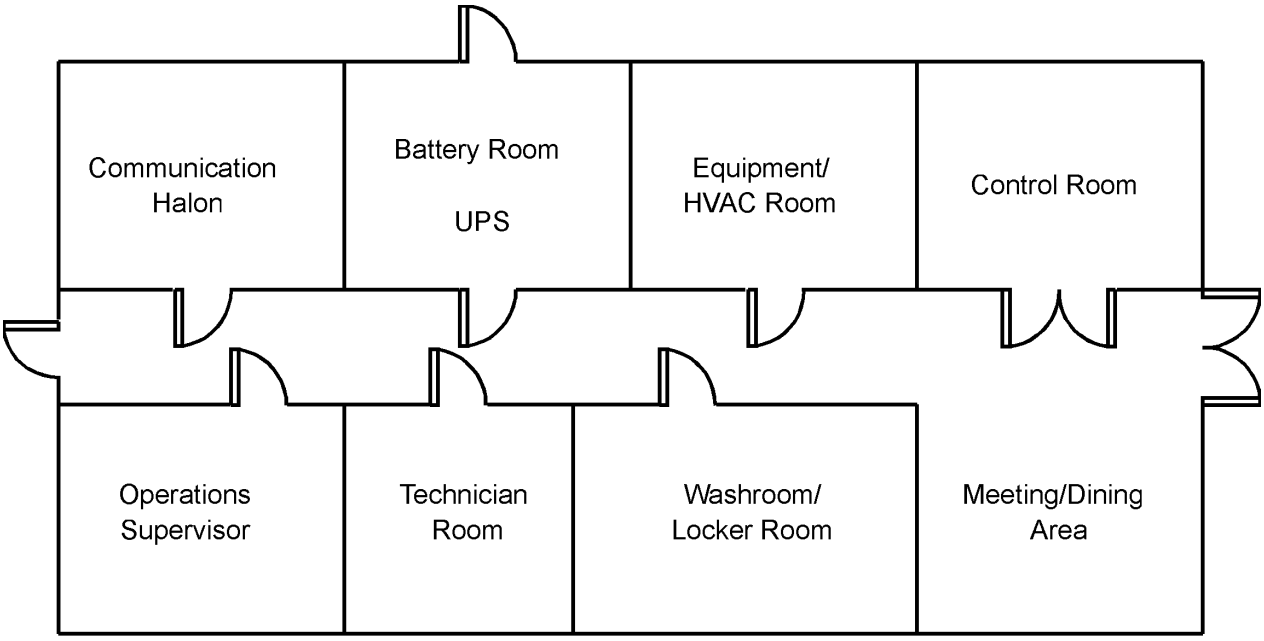

Figure 2: Small Control Center Plan–Onshore

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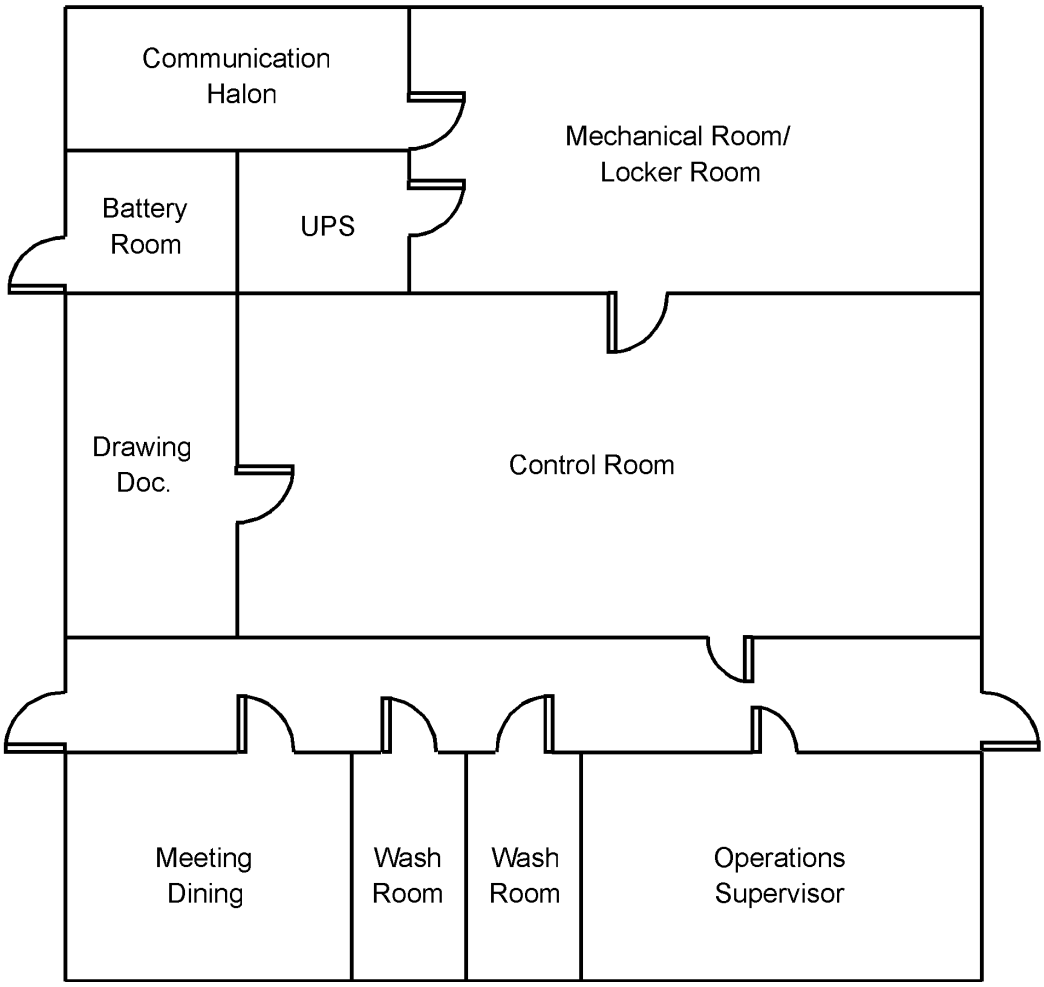

Figure 3: Small Control Center Plan–Offshore

2.2.3. Control Center Requirements

- The control center shall be a single story building comprising a number of rooms, each serving a specific purpose.
- There shall be a minimum of two separate entrances. Easy access to the process area by personnel in the control center shall be a consideration when locating the control center entrances, but is not essential, especially in large plants.
- Offices shall be provided for the day supervisor and shift supervisor(s).
- Each office shall be equipped with a monitor and printer that provide a direct window to the process.
- A locker room, washroom and multipurpose room(s) (eating, conference, training, etc.) shall be sized and provided as required.

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2.3. Control Room

The operator interface with the process is through an operator console consisting of a number of video displays and keyboards and some ancillary equipment such as trend recorders, annunciators, various pushbuttons and lights, and a two-way radio communication system with the outside operator. From this operator console one operator can control a number of processes. Depending on the size of the plant, a number of operator consoles can be arranged in a control room with each operator console having one dedicated operator.

- The design of the operator console shall allow at least two operators to operate independently and freely from the console during startup or a major plant upset.
- Each operator console shall be provided with sufficient clearance from other operator consoles, walls and other equipment or obstructions to allow free access for a maximum number of operators in the worst operating case, such as during startups, turnarounds and emergencies.
- Equipment location shall not impede free control room access by normal or emergency doorways.
- The control room shall be designed to allow free and easy access to all the operator consoles or other equipment located therein. As a minimum, the clearances in the following table shall apply.

Rear of equipment to wall	1.5 m	(5 ft)
Rear of operator console to wall	1 m	(3 ft)
Front of operator console clearance	1.8 m	(6 ft)
Front of equipment abutting wall	1 m	(3 ft)
Freestanding printer	1 m	(3 ft)

NOTE: Where space is at a premium, allowances can be made for access clearances, but access space to all equipment maintenance, test and connections points shall be provided.

- All freestanding panels or consoles shall be bolted to the floor in their final position. Tables supporting printers and video copiers shall be fixed to prevent stretching of interconnecting cables and possible accidental disconnection.
- All paper for printers and hard copy units shall be stored elsewhere. Recharging units for portable two-way radios shall not be mounted in the control room.
- Hardwired annunciators shall be provided for a limited number of critical alarms. These annunciators may be mounted in an operator console or mounted independently and suspended from the ceiling above the related operator console.
- Closed-circuit television used for security or monitoring shall be mounted at a convenient elevation where it can be viewed by an operator seated at the operator console. Closed-circuit television shall be provided to monitor the flare and areas of the process units.

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- A computer-type floor, as specified in Section 3.6 of this MEP, shall be used throughout.

2.4. Rack Room

Depending on the plantwide control system layout, the control center rack room may contain equipment connected directly by signal wires to the process or by data cables connected to controllers located in field enclosures or both.

- Terminations and entries of field cables shall be in accordance with MP 32-P-21.
- A computer-type floor, as specified in Section 3.6 of this MEP, shall be used throughout.
- All instrument wiring, data highways cables and power wiring shall run beneath the floor. Instrument wiring and data highway cables shall be segregated from power wiring.
- Double doors shall be provided of an adequate height and width to allow equipment to be brought into the room in an upright position.
- The rack room shall be located adjacent to the control room and UPS room and have an outside wall to allow direct entry of field cables. All cable entries shall be sealed against groundwater intrusion and, where applicable, to provide hazardous area separation.

2.4.1. Cabinets

- The equipment room shall contain the field termination cabinets for the termination of all incoming field signals, alarm and thermocouple cables. These cables shall be connected through the wall directly into the field termination cabinets.
- Cabinets for programmable electronic systems (PES) shall be freestanding and arranged in parallel rows, with adequate surrounding space for maintenance. They shall be bolted to the floor and to one another, where appropriate.
- All cabinets mounted against the wall shall be bolted to the wall in their final positions.
- Adequate clearance shall be provided above the electronic field interface cabinets, in order to allow the cooling specified by the equipment manufacturer.
- A working area of approximately 6.7 m^2 (72 ft^2) shall be provided for a workbench and for storage cabinets for electronic test equipment.

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2.4.2. Field Interface Units and Distribution Panelboards

- Power distribution panelboards and the field interface units shall also be located in the rack room. The distribution panelboards shall be mounted on the wall separating the rack room from the UPS room.
- The field interface units shall be freestanding and arranged in parallel rows with adequate surrounding space for maintenance. All equipment shall be bolted to the floor and to one another where appropriate.
- Adequate clearance shall be provided above the electronic field interface cabinets to allow the cooling specified by the equipment manufacturer.

2.5. Computer Room

A room shall be provided for the computers and engineering workstations. The room shall be sized to allow easy access to the computers selected for the project with sufficient space allowed for two additional computing cabinets and associated hard disks, a printer and a terminal.

- A computer-type floor, as specified in Section 3.6 of this MEP, shall be used throughout.
- The computers and their peripherals shall be freestanding or, if necessary, desktop mounted. There shall be free access for operation and maintenance.
- Computers and engineering workstations shall be wired to the UPS.
- Cables shall be clamped to the chassis of the equipment they serve to avoid strain on the connections and inadvertent disconnections.

2.6. Permit Room

A room shall be provided for the purpose of interfacing with maintenance and other non-operations personnel. Issuing work permits and picking up reports and logs are two examples.

The permit room may also serve as a place to locate the charger units for portable radios, as well as for printer paper storage and short-term filing of reports.

2.7. UPS Room

The UPS shall be located in its own room. Either several UPSs (maximum number of three) or one UPS with multiple static switches shall be provided. Diversity of load shall be provided by dividing the loads of each operator station between the UPSs or multiple static switches in such a way that the failure of a UPS or static switch shall result in the loss of only part of the operator station.

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- A computer-type floor, as specified in Section 3.6 of this MEP, shall be used throughout.
- The UPS preferably shall be installed against and along the length of one wall, if rear access is not required.
  - If rear access is required, then the UPS cabinets shall be freestanding with a minimum clearance of one meter between the cabinets and the walls.
  - In either case, the cabinets shall be rigidly bolted to the floor and to one another.
- Entry to the room shall be large enough to allow free passage of the UPS cabinets.
- The UPS System shall be in accordance with MP 33-P-16.

2.8. Battery Room

The battery room shall be adequately sized to provide easy access to the batteries.

- Access to the battery room shall be, preferably, from the outside only.
- The battery room shall be adequately ventilated in accordance with API RP 500. The ventilation shall be designed to allow the purge flow of exhaust air from the building air conditioning system to maintain the battery room at a temperature of no higher than 25°C (77°F). Refer to NFPA 70 for general safety features.
- For mounting and support of batteries, see MP 33-P-15.

3. Building Infrastructure

3.1. Environment and Security

Central control rooms are not intended as the meeting point between the control room and outside operators. The control room contains electronic equipment that, though of rugged construction, can be damaged through misuse and by exposure to unnecessary dust, humidity and hostile atmospheres. For these reasons, normal control room traffic shall be limited to control room operators and operating supervisors.

Environmental and protection systems shall conform to the requirements of MP 70-P-01, MP 70-P-09 and MP 33-P-23.

3.1.1. Lighting and Color

- The control room lighting shall be designed to provide adequate illumination in working areas and to avoid glare and reflections in the operator station CRTs.

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  - This may be best achieved by providing concealed lighting in the center of the room with the operator consoles arranged around the outside of the room.
  - Another approach is with lighting directly above work areas with separate illumination level controls for each area.
  - Use of fluorescent lighting shall be carefully designed to avoid interference with electronic control equipment.
- The control room shall be painted a neutral color, enhanced by decorative features that together create a pleasant working environment for operators who may sit for hours without any close interaction with the plant operation.

3.1.2. Climate Control

The overall temperature and humidity shall be controlled according to a Class A2 location, Level 2 severity, as defined in ISA S71.01.

- Makeup air shall be filtered and conditioned to remove any toxic and other constituents that may be harmful to the installed electronic equipment.
  - Particular care shall be taken to ensure the electronic instrument manufacturer's requirements in this regard are met.
  - As a minimum, the airborne contaminants shall be removed to satisfy the requirements of ISA S71.04.
- Distribution of the conditioned air is vital to the reliable operation of the control system. Consequently, the heat generated by each electronic cabinet shall be determined and the location of the various heat sources known, so that adequate cooling is provided where it is needed most.
- Heating, ventilation and air conditioning shall be designed in accordance with MP 41-P-30.
- Air conditioning ducts shall be supported on resilient mountings to minimize noise.

3.1.3. Escape Paths

The rooms within the building shall be connected by corridors with no direct access from the outside to any room, except for the battery room, which shall be accessed only from the outside. Doors for equipment removal only shall be kept locked during normal operation.

If there is no easy escape path through the building in an emergency, emergency doors to the outside shall be provided in any room containing electrical equipment.

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3.2. Wiring

Power, instrument and data highway cables shall be segregated from one another. Refer to MP 32-P-21 for detailed requirements.

- Cables running beneath the floor shall be clear of the air conditioning ducts and supported on trays at crossover points.
- Cables passing through firewalls from room-to-room shall do so via cable transits designed to prevent the propagation of fire.
- All signal wiring, data highway cables and power wiring shall run beneath the floor. Signal wiring and data highway cables shall be segregated from power wiring.
- Cables shall be clamped to the chassis of the equipment they serve to avoid strain on the connections and inadvertent disconnection.

3.3. Communications

A voice communications system (refer to MP 33-P-32) that enables the control room operator to communicate with the outside operator shall be provided in the control room.

- The system shall be selected with acceptable frequency bands that allow discrimination between various types of system users, such as process operators, utility operators, oil movement tank farm operators and maintenance personnel.
- The system shall allow two-way communication from each operator station and be designed for a handset. This will allow an operator to communicate with outside operators without disturbing others in the control room and for a broadcast system clearly audible 3 m (10 ft) from the loudspeaker.
- Communication systems can cause interference with electronic control equipment and result in process interruptions and shutdowns. Consequently, large permanent signs prohibiting the operation of portable transmitters in any room containing control equipment or in close proximity to uncovered (unshielded) electronic equipment shall be prominently placed in and around the control center.
- An adequate number of telephones and telephone jacks shall be provided, in order to allow maintenance people access to phones, should telephone support be required.

3.4. Grounding

Two separate grounding systems shall be provided: one for power safety ground and the other for signal common ground.

- The power and signal common grounds shall be connected together at one point only.
- Node plates shall be provided at a convenient, accessible location in the equipment room to allow the resistance to ground to be measured.

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- Ground electrodes shall be provided in accordance with MP 33-P-26.
- The computer floor shall be grounded to the power ground.
- Interconnecting wiring between signal ground buses in termination cabinets and between termination cabinets and node plates shall be insulated.
- All cable shield drain wires shall be connected to the signal ground buses in the termination cabinets.
- The specific manufacturer's requirements for grounding of the distributed control system (DCS), programmable logic controller (PLC), computer and other instrument equipment shall be followed and modified, as mutually agreed, to satisfy the local code requirements.

3.5. Electric Power

Three-phase power, having a grounded neutral, shall be provided to the control center from at least two independent sources.

- The distribution boards in the rack room shall have a main circuit breaker. The main breaker and the branch circuit breakers shall have adequate coordination to prevent the propagation of a fault in the branch circuit to the main breaker.
- Service outlets shall be provided in the control room, computer room and rack room for test equipment.
- UPS AC, non-UPS AC and DC power distribution panels shall be installed in the UPS room in accordance with EPT 06-T-06.

3.6. Raised Floors

- A raised computer floor shall be installed in rooms containing operator consoles, instrument racks and computers to allow easy routing of signal and power wiring.
  - Unless otherwise specified, a rigid support structure with bolted-down stringers shall be provided for the raised floor. These stringers shall be spaced or have holes to permit cable distribution.
  - The depth below the computer floor to the subfloor shall be a minimum of 381 mm (15 in).
- The concrete surfaces of the floor, and the walls beneath the computer floor, shall be sealed against dust and moisture penetration.
- An interlocking type of anti-static computer floor is preferred throughout the control room. In addition, antistatic mats shall be placed alongside electronic equipment.

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Safety Interlock Systems and Alarms

MP 32-P-07

July 1998

Scope

This Mobil Engineering Practice (MEP) covers the basic requirements for the design, installation and maintenance of Safety Instrument Systems (SIS).

Using industry standards, this MEP provides a systematic path for the selection, application and maintenance of SIS. It also seeks to build on Mobil past experience and design practice to achieve the best consistent design practice.

Version 0

Table of Contents

Scope **1**

1. References **4**

1.1. Mobil Data Sheets 4

1.2. ISA–Instrument Society of America 4

2. General **4**

3. Safety and Reliability **4**

4. Implementation Process **5**

4.1. Conceptual Process Design 5

4.2. Hazard Analysis and Risk Assessment 5

4.3. Non-SIS Protection Layers 5

4.4. SIL Level 5

4.5. Safety Requirements Specification 5

4.6. SIS Conceptual Design 6

4.7. SIS Detailed Design 6

4.8. SIS Installation Commissioning and Test 6

4.9. Pre-Start-Up Safety Review 6

4.10. SIS Start-Up, Operation, Maintenance and Periodic Functional Testing 6

4.11. SIS Decommissioning 6

5. Design Practice **6**

5.1. Logic Solver Selection 7

5.2. Field Devices 10

5.3. Maintenance By-Passes 13

5.4. Start-Up By-Passes 14

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5.5. Alarm Handling and Sequence of Events 14

5.6. External Systems Communications 16

5.7. Power Supplies 17

5.8. Systems Testing 18

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1. References

The following publications form a part of this Practice. Unless otherwise specified herein, use the latest edition.

1.1. Mobil Data Sheets

Mobil Data Sheets	Mobil Data Sheet Home Page
T3207C01	Safety Interlock Systems & Alarms - Safety Interlock Systems & Alarms - Customary Units
D3207C01	Safety Interlock Systems & Alarms - Documentation Requirements Sheet
I3207C01	Safety Interlock Systems & Alarms - Inspection & Testing Requirements Sheet

1.2. ISA–Instrument Society of America

ISA S18.1	Annunciator Sequences and Specifications R(1992)
ISA S84.01	Application of Safety Instrumented Systems for the Process Industries

2. General

The design, installation and maintenance of SIS shall be in accordance with requirements of this MEP, unless superceded by more stringent local regulations.

The terms, definitions and acronyms used in this MEP are defined in ISA S84.01.

3. Safety and Reliability

While ISA S84.01 focuses on safety, the SIS shall be designed so that its reliability equals the defined targets set by the facility. Specific consideration shall be given to the projects/facilities cycle time between complete shutdowns; this will provide a clear understanding of the design requirements to meet appropriate reliability targets.

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4. Implementation Process

The implementation to be followed is described under the "Life Cycle" steps in ISA S84.01. However, not all of the methodology required for implementing each step is included in ISA S84.01. This MEP lists the methodologies and practices which shall be used. The Life Cycle steps are listed below, with a reference to the methodology or practice to be used.

4.1. Conceptual Process Design

This refers to the design of the petrochemical process and is not covered by this MEP. It is the existence of this petrochemical process that necessitates the need for an SIS to be considered.

4.2. Hazard Analysis and Risk Assessment

This refers to the identification of the hazards in the petrochemical process and assessing the level of risk involved. This process is not part of this MEP; however, to design and then implement an SIS appropriately, the output of a Hazard Analysis must be a direct input into the SIS design.

4.3. Non-SIS Protection Layers

The application of non-SIS layers is a key step in the "Safety Life Cycle" model and as such shall be an integral part of the project design cycle. The application of non-SIS protection layers shall be done so that wherever possible the non-SIS layer eliminates the need for an SIS layer to mitigate the identified hazard or risk.

4.4. SIL Level

If an SIS is required, then a target SIL level for the SIS shall be defined as part of the Hazard Analysis and Risk Assessment phase of the project. The SIL level coming from the Hazard Analysis and Risk Assessment phase of the project defines the level of performance needed to achieve the safety objective. Without these parameters being defined, the detailed engineering associated with the SIS cannot be undertaken.

4.5. Safety Requirements Specification

Refer to ISA S84.01 for a description and guidelines on this process.

The Safety Requirement Specification (SRS) shall be developed to ensure that all criteria designated and conceived prior to the engineering design phase of the project are

developed into a fully descriptive abstract of their individual representations. These occur in the initial pre-engineering phases of the project where all project details are fully discussed, analyzed and concluded. All actions and decisions made during the pre-engineering phase shall be addressed in the SRS document.

Certification of the SRS shall be treated as the initial Quality Assurance step prior to beginning detailed design and engineering project phases. The SRS shall be the defining specification on which detailed design is focused and achieves a secondary purpose of minimizing downstream engineering changes.

4.6. SIS Conceptual Design

Refer to ISA S84.01 for a description and guidelines on this process.

4.7. SIS Detailed Design

Refer to ISA S84.01 for a description and guidelines on this process.

4.8. SIS Installation Commissioning and Test

Refer to ISA S84.01 for a description and guidelines on this process.

4.9. Pre-Start-Up Safety Review

Refer to ISA S84.01 for a description and guidelines on this process.

4.10. SIS Start-Up, Operation, Maintenance and Periodic Functional Testing

Refer to ISA S84.01 for a description and guidelines on this process.

4.11. SIS Decommissioning

Refer to ISA S84.01 for a description and guidelines on this process.

5. Design Practice

The following design practices give guidance on how to implement specific features of a practical SIS.

5.1. Logic Solver Selection

SIS system design platform and selection shall be the joint responsibility of Mobil and the contractor. An SIS system shall be implemented by a triple modular redundant (TMR) programmable electronic system.

Depending on the application, it may be advantageous to implement the SIS system using an alternative architecture. If this is allowed, then safety and reliability targets shall be met for each specific subsystem.

The following criteria shall be used as minimum requirements for the TMR programmable electronic system.

5.1.1. Hardware

Consideration is to be given to the standardization of the types of hardware specified for the SIS system used in a plant or on a project for the purpose of spare parts holdings, maintenance familiarization, etc.

- In no case shall a PES be used if it is based on a custom programmed microprocessor, i.e., a "one-of-a-kind" system.
- When a portion of a packaged unit is assessed as an SIS system, then that shall be integrated according to the details specified in the projects SRS.
- The provision of a number of discrete protective systems (possibly on the basis of one per process unit) is preferred to one large system, because it allows a process unit and its associated protective system to be taken off-line simultaneously without affecting any other unit. The actual number of protective systems used will depend on the interdependence of the units involved. The decision on how the SIS are to be segregated shall be facilitated with input from both process and operational personnel.

5.1.2. Software (System)

Automatic self-testing and system diagnostics shall be incorporated in all SIS configurations. All testing and system diagnostics shall be a proven integral part of the standard system and shall be completely transparent to the user when the application is implemented.

5.1.2.1. Malfunction Diagnostics

System diagnostics shall identify all possible faults and provide a means to annunciate diagnosed malfunctions. An alarm shall be initiated in the event of any malfunction or authorized maintenance procedure, which as a minimum, shall consist of the following.

1. Removal of, or any defect in, any logic unit, communication module or processor

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2. Removal of, or any defect in, an input or output module or channel on a module

3. Power supply failure

It is unnecessary to remotely annunciate each alarm individually, provided a common alarm is initiated and the fault can be identified.

5.1.2.2. On-Line Self-Testing

Systems shall be designed for high availability, with on-line self-testing. As a minimum, the following basic functions shall be verified by on-line testing. The frequency of the self diagnostic tests shall be no more than once per day.

1. Individual check of the system's ability to change the state of an input channel

2. Individual check of the system's ability to change the state of an output channel, i.e., loopback testing feature

3. Check of the logic-solving ability

4. Standard programmable logic controller diagnostics (watchdog, etc.)

5. Power-up initialization checks and checks for communication failures

6. Testing of field wiring and end-of-line devices (ELDs)–this testing method strongly recommended

5.1.2.3. Scan Time

The scan time of the SIS shall match the needs of the system being protected. Consideration shall be given to how fast the system can move from detection of an upset condition to occurrence of a hazardous situation. A turbine protection system, for instance, may have to respond in milliseconds, while for some processes a second may be fast enough.

5.1.2.4. Security Measures

The protective system implemented by a PES shall be adequately protected against unauthorized access by keylock or password or a combination of both.

5.1.3. Software (Application)

The preferred application language is a ladder or functional logic diagram with extensions to accommodate analog inputs.

The requirements of the application software shall be clearly defined using either cause and effect diagrams, functional logic diagrams or flow charts.

- Functional logic diagrams or cause and effect charts are recommended for interlocks and shutdowns.

- Flow charts are recommended for sequencing.
- Whichever method is chosen, the representation shall be kept as simple as possible to allow participation by noncontrol system specialists such as operations, loss prevention and process engineers.

5.1.3.1. Application Development Tools

Consideration shall be given to using application development tools that allow the PES application software to be presented in one of the preferred methods. This will:

- Eliminate a large portion of work through the design phase
- Eliminate coding errors in not having to translate the application specification from a functional logic diagram to ladder code
- Provide effective documentation

5.1.3.2. Self-Documenting PESs

The PES shall be self-documenting. All protective system PESs shall be self-documenting in:

- Original programming of the application
- Any changes made after the installation

The following shall be generated as a minimum:

1. A program listing that includes a functional description
2. A system configuration
3. Logic or ladder diagrams
4. A cross-referenced listing of tag numbers and program use locations

The application software shall be structured and annotated to provide anyone with a good understanding of the protection implemented.

5.1.3.3. Modifications to Software

- Changes to software after Factory Acceptance Tests (FAT) shall not be permitted unless the changes are submitted to rigorous design change verification, thoroughly tested functionally and fully documented.
- Unauthorized modifications of software shall be restricted. The restriction shall typically be in the form of a keylock and password. The keylock will prevent altered software from being downloaded to the protection system and the password will prevent unauthorized software code modification on the programming terminal.

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5.1.3.4. Memory Use

The application software shall not use more than 60 percent of the available system memory. The central processing unit shall, under normal working conditions, be less than 50 percent loaded. This loading shall be demonstrated during the FAT. Worst case conditions shall also be simulated to determine if degradation of loading is within acceptable limits. These include multiple alarms, automatic shutdowns and so forth.

5.1.3.5. SOE Handling

Sequence of events (SOE) handling shall be implemented so that time and date stamping provides a correct sequence for troubleshooting. Generally this shall be via the PES itself or via a dedicated PC. DCS shall not be used as a SOE recorder.

5.1.3.6. Other Requirements

- The system shall allow application software to be developed and tested off-line on an IBM or compatible personal computer (PC).
- It shall be possible to change the application program on-line without disturbing the process.
- It shall be possible to download at least minor changes in software from the programming terminal to the protective system while it is on-line without disturbing the operation of the plant. Adequate testing procedures shall be available to verify the new logic prior to activating it in the on-line program.

5.2. Field Devices

The SIS is made up of subsets including the field devices (inputs to the PES and outputs from the PES). Consideration shall be given to the general field device requirements when developing the Safety Requirement Specification for the project. Specifics to be considered are:

1. Standard configurations for inputs into the PES to be adopted for the project. These shall encompass what types of testing regimes are required to meet the SILs and reliability targets. The SIS's operating period requirements will then be integrated into the design for the project. This will then ensure that a consistent approach is taken as well as minimizing the chance of design recycle.
2. Standard configurations for outputs from the PES to be adopted for the project. These shall encompass what types of testing regimes are required to meet the SILs and reliability targets. The SIS's operating period requirements will then be integrated into the design for the project. It is critical that the project strategy on how to address the final element be defined early in the design phase to minimize cost.

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5.2.1. Shutdown Initiators

The use of transmitters as shutdown initiators is preferred to switches.

5.2.2. Field Devices

Field devices shall be dedicated to the SIS.

5.2.2.1. Design Considerations

Where multiple field devices are used as initiators of the same process condition, they shall conform to the following design considerations:

- Each device shall be installed on a dedicated process connection (tapping). Manifolded arrangements may be used, provided that individual isolation and test facilities are available.
- Devices shall be assigned to separate input modules of the PES to ensure segregation and eliminate common points of failure.

5.2.2.2. Rule Set

Rule set shall be developed for field device configuration, which defines the following as a minimum. The example in Table 1 provides guidance:

- Device configuration
- PES module assignment
- Method of trip initiation within PES
- Required mapped points onto the DCS

The discrepancy alarms mapped to the DCS provide a means to ensure that the field devices can be maintained to support the SIL targets based on actual faults rather than implementing a periodic testing regime.

The actual analogue trip signal mapped onto the DCS as a dynamic analogue value provides valuable information to operational personnel. It provides a means to ensure that all changes made to trip values within the PES under MOC are transparently obvious and automatic to operational personnel.

Table 1: Example Rule Set

Field Configuration	PES Input Requirements	Trip Initiation (PES)	Mapped to DCS
1oo1 Switch	Single DI module	Logic 0	Switch position
2oo2 Switch	Each switch into independent DI	Both switches indicate a logic 0	Combined switch position Discrepancy alarm

Field Configuration	PES Input Requirements	Trip Initiation (PES)	Mapped to DCS
	modules		Tripped alarm
Double Block Valve Status	Open and close limit switches of each valve into same DI modules	Logical open and logical closed based on limit switch positions and solenoid state	Open/closed indication Discrepancy alarm
Double Block and Bleed Valve Status	Open and close limit switches of each valve into same DI modules	Logical open and logical closed based on limit switch positions and solenoid state	Open/closed indication Discrepancy alarm
1oo1 Transmitter	Single AI module DI for bypass function	Analogue value compared directly with trip value	Analogue process value Analogue trip value Tripped alarm Bypass initiated alarm
1oo2 Transmitter	Each device into independent AI modules DI for bypass function	Lowest or highest analogue value (dependent on whether HH or LL trip) compared directly with trip value	Initiating analogue process value Analogue trip value Discrepancy alarm Tripped alarm Bypass initiated alarm
2oo2 Transmitter	Each device into independent AI modules	Both analogue values compared directly with trip value	Initiating analogue process value Analogue trip value Discrepancy alarm Tripped alarm
2oo3 Transmitter	Each device into independent AI modules	Mid analogue value compared directly with trip value	Initiating analogue process value Analogue trip value Discrepancy alarm Tripped alarm

5.2.3. Input Switches

When switches are used as inputs to the system, they shall be voltage and ground free and shall be closed during normal operation. Limit or proximity switches shall closed for the status being monitored, such as closed when shut, closed when open and closed when running.

5.2.4. Emergency Shutdown Switches

Consideration shall be given to implementing emergency shutdown switches with 2 pole switch (in a 2oo2 configuration) to eliminate common points of failure.

Emergency manual shutdown switches shall be hardwired directly to the input of the PES system.

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Switches shall be protected from inadvertent operation by providing them with shrouds or flaps and by clearly labeling them with a description of their duty.

5.2.5. Final Shutdown Devices

Final shutdown devices (trip devices) such as solenoid valves shall be designed and installed so that, when de-energized or depressurized, they will cause a shutdown of the equipment they protect.

- The use of dual redundant (2oo2) solenoid valves on shutdown valves shall be considered on the same basis to provide robustness against single failure.
- Each solenoid shall be driven from a separate output module of the PES and each solenoid coil shall be continuously monitored for open circuit.
- Both solenoids shall be de-energized to trip.
- There shall be a method of testing each solenoid valve individually.

5.2.5.1. Manual Reset

Trip devices driven from the PES such as solenoids shall require manual reset to re-establish the system after a shutdown. The reset method will be a function of the operating philosophy of the facility and type of system to be reset.

Methods shall generally be accomplished by one of the following:

- Solenoid valve has mechanical reset mechanism and logic self resets when permissives are met.
- No mechanical reset mechanism on solenoid valve and logic has to be reset by a reset switch into the PES, either initiated from the field or control room.

All manual resets shall be easily accessible by operators and located so that safe operation of the plant can be ascertained before actuation.

5.3. Maintenance By-Passes

Maintenance and process (start-up) by-passes shall be treated as separate entities. The following principles shall apply when dealing with maintenance by-passes.

- Maintenance by-pass functions shall form part of the overall SIS design, to meet the projects required maintenance and testing regimes.
- Under no circumstances shall manual emergency shutdown switches be bypassed.
- Maintenance by-pass switches shall not operate multiple bypass functions.

- Maintenance by-pass switches shall be implemented by directly wiring the switch into the PES as a digital input signal and by-pass functionality carried out by the PES's application software, in preference to external hardwired systems.
  - Operation of the by-pass shall be alarmed on the DCS.
  - By-pass switches shall not inhibit associated process alarms.

5.4. Start-Up By-Passes

Process (start-up) and maintenance by-passes shall be treated as separate entities. The following principles shall apply when dealing with process (start-up) by-passes:

- Process (start-up) by-pass functions shall be minimized and engineered out of the SIS design. This shall entail the development and application of advanced logic to enhance the SIS.
  - An example of this would be the elimination of a process by-pass for the low pass flow fuel gas trip of a heater for start-up.
  - The application software of the SIS can be developed to ensure that the low pass flow trip is a valid trip (and thus activated) only if the appropriate conditions or states are valid.
- Under no circumstances shall the manual emergency shutdown switch or switches be by-passed.
- In the event of process (start-up) by-pass switches being required, they shall be implemented by directly wiring the switch into the PES as a digital input signal; they shall by-pass functionality carried out by the PES's application software, in preference to external hardwired systems.
  - Preference shall be given to switches that are momentary in operation with the PES software providing automatic reset.
  - Operation of the by-pass shall be alarmed on the DCS.

5.5. Alarm Handling and Sequence of Events

5.5.1. Control Room Alarms (Process)

- Pre-shutdown alarms shall be generated and displayed by the plant DCS. If a plant DCS is not available, pre-shutdown alarms shall be implemented by annunciators. If the process variables are being measured by non-SIS transmitters, then consideration shall be given to initiating pre-shutdown alarms from non-SIS transmitters.
- Shutdown alarms displayed by the DCS shall be initiated by the same logic that implements the shutdown. DCS inputs shall provide an independent and positive indication that an SIS has executed a shutdown.

- Consideration shall be given to the technology of expert systems to enhance alarming and PES's. Features of these systems may include:
  - Qualifying individual alarms by comparing against other input criteria
  - Providing criteria for rate of change
  - Predicting when a dangerous condition is about to occur and cutting back on critical variables to bring the process or equipment into a safe operating region
- Note that the application of expert alarm systems will most likely be a combination of PES and DCS. Caution that the PES shall not be compromised in carrying out its function to safely protect the facility at the expense of alarms or alarm systems.

5.5.2. Control Room Alarms (System)

Alarms generated by the SIS (as per requirements of Section 5.1.2) shall be annunciated in a central, permanently manned control room. Evaluation shall be carried out on the most appropriate method to implement to be consistent with the overall alarm management philosophy. Implementation may either be :

- Hardwired annunciation panels
- Software alarms onto the DCS

SIS systems alarms shall be clearly segregated or distinguishable from process related alarms.

5.5.3. Field Alarms

5.5.3.1. Audible Alarms

Audible alarm devices (horns, sirens, buzzers, etc.) shall be selected with consideration to the service and the possible impact if the alarm device fails to operate. In cases where the audible alarm is integral to the annunciation of a problem it may be necessary to use an air horn actuated by a solenoid valve in a de-energize to sound configuration. All audible alarms shall have sufficient sound power output to be recognized above ambient plant noise from a distance of 50 m.

5.5.3.2. Visible Alarms

Visible alarms in the field or located on local field panels shall be oriented and shaded to ensure that alarms are clearly visible in bright sunlight. LED clusters (versus incandescent lamp) shall be used for visual indicating lamps to provide reliable and fault free operation.

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5.5.3.3. Alarm Functionality

Consideration shall be given to implement required alarm functionality (as per ANSI/ISA S18.1) from the application program of the PES, allowing the use of simple devices in panels. The same signals can then also be used to map through onto the DCS with the same functionality.

5.5.3.4. Visibility of Annunciator Lamps

Test, acknowledge and reset buttons shall be located so that all affected annunciator lamps are clearly visible from the button location. If the PES is implementing the alarm functionality, the test feature shall be directly into the PES, thus testing the entire system.

5.5.3.5. Use of Beacons

Annunciators in noisy areas shall have a rotating beacon that operates simultaneously with the audible alarm. Also, a beacon shall be provided when there is more than one annunciator in the same location.

5.6. External Systems Communications

An operator interface shall be provided to indicate the status of the relevant inputs, outputs and PES application program generated flags. This shall be either a serial link to a DCS system or a separate dedicated operator station (an industrial workstation or a personal computer) or conventional instrumentation (an annunciator).

5.6.1. Inputs and Outputs

Inputs to and outputs from the system shall be capable of being displayed to the operator in the main control room.

- Inputs are mainly indications of alarms, bypasses, push-button status and system malfunctions.
- Outputs, for operator information, are status indications of compressors, valves, motor drives and so forth.

5.6.2. Annunciator Requirements

The requirements of Section 5.5 shall be followed, regardless of which form of annunciation is used.

5.6.3. Component/Equipment Failures

The operator interface shall not be used as a programming terminal, nor shall it allow any access to the application program or affect the operation of the protective system in any way. Failure of any component in the operator interface shall not cause a spurious shutdown, nor shall the component failure go undetected.

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Failure of equipment associated with communications shall not affect safety related functions or prevent other devices on the communication circuit from operating.

5.6.4. Printer

All PES's shall be provided with a local printer. The purpose of this printer will be to aid maintenance troubleshooting.

- The printer shall log all changes of state into and out of the system and all changes of state of system variables (those variables that indicate the "health" of system components).
- The printer shall log tag numbers, times of day and a brief description of the state that has changed. The printed time will normally be to the resolution of milliseconds and be accurate to the scan time of the system.
- An option shall be available to "print to disk" if continuous output of hardcopy is undesirable (a local printer is still required).

5.7. Power Supplies

Primary power is that power necessary to power the SIS's PES. It also includes the power necessary for the following classes of loads:

- Input/output modules
- Switch excitation voltage
- Solenoid valves
- Transmitters

The power source is an integral part of the SIS and its reliability shall be included in the overall assessment of whether the SIS meets defined reliability targets.

5.7.1. Configuration

The power supply configuration to the SIS shall be kept as simple as practical with consideration given to local needs, unique requirements of the project and the criticality of the process or processes being protected.

5.7.2. Design Considerations

The final design for the SIS's primary power system shall be based on the following design considerations:

1. The preferred primary power to an SIS is 24VDC. Primary power using 120VAC or 240VAC shall have the approval of Mobil.

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2. The primary power source to an SIS shall be able to supply power for a period of not less than 30 minutes when the supply is interrupted to the primary power source.

3. The SIS and its sub-components shall be selected so that two supply sources are able to be connected; the power supply paralleling shall be integral to the equipment design. This eliminates the need for complicated paralleling schemes in the electrical supply configuration (see attached diagram) and thus a common point of failure.

4. The source of AC power to power the primary supplies does not need to be from another separate UPS system, as the primary power sources themselves provide the capacity. The preferred configuration is a separately sourced AC breaker wired directly to each of the dual redundant primary power supplies.

5. Primary power supply systems for SIS's shall have, as a minimum one common alarm as an input to the SIS or facility DCS so that any fault on the power supply systems is annunciated in a permanently manned location. The common alarm shall annunciate the following, as a minimum:

   a) Loss of supply to the system

   b) Charging system fault

   c) Low battery

6. The primary power supply shall be sized to the requirements of the installed load with approximately 50 percent excess capacity.

7. The electrical distribution to the SIS (including sub-components) shall be arranged so that no single fuse failure or fault will affect the availability of the entire system.

5.8. Systems Testing

System costs and delivery schedule shall include adequate funds and time for a thorough witnessing of all acceptance tests. The form of testing depends on how the total system is integrated.

1. Typically, the following components will be tested as a complete system by a single vendor or as separate parts:

   – Logic processor and input/output modules

   – Operator interface

   – Application program

2. When the complete system is brought together, the tests at each stage shall be extensive. Typically, the stages of testing can be broken down as follows:

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- Vendor hardware and software tests
- Factory Acceptance Tests (FAT)
- Site Acceptance Tests (SAT)

3. The tests undertaken at each stage shall depend on a number of factors and the final choice shall be based on individual circumstances. The paramount requirements are:

   a) The system is tested as an integrated system.

   b) The tests are extensive.

   c) The vendor's responsibilities are fulfilled.

   d) All tests are documented in a checklist fashion.

   e) The system is fully proven before going into service.

   The test procedures shall be developed in parallel with the system design.

4. The provision of a test procedure shall be part of the purchase specification. These test procedures shall be developed by the vendor as system engineering proceeds and shall be submitted for Project approval at least one month before commencement of the first factory test.

5. The test procedure shall be designed so that in the event of a failure of a portion of the test, Mobil can determine the extent of the retesting required.

5.8.1. Vendor Hardware Tests

Comprehensive hardware tests shall be completed by the vendor prior to any acceptance tests by Mobil. Normally, this is undertaken as part of the manufacturer's quality control procedure.

- All modules will be tested individually after being installed in the purchased system. It is possible that a heat soak test will be included.
- For a software based system, the vendor shall provide documented test programs that fully exercise all functions in the purchased system.
- The vendor's quality control test records shall be made available for examination.

5.8.2. Factory Acceptance Test (FAT)

Before the system is delivered to the site, satisfactory performance of the entire system shall be demonstrated to the project's designated representative. The system shall simulate the final onsite configuration as closely as possible.

The following tests are recommended. They shall be developed in detail during preparation of the test procedures. The vendor shall have a technician and test equipment available full time during testing.

1. Inspection of equipment
2. Shock or vibration test (Not necessary to run for each system under test, but certification shall be made available by the vendor for the generic system.)
3. Power supply variations
4. Radio interference test
5. Functional tests, including:
   - Operator control panel functions
   - Module replacement and standby changeover
   - Operation of multiple processors
   - Operation of communication channels, including the PES to DCS communication link
   - Operation of power supplies
   - Failures and interaction between different parts of the system
   - Systematic diagnostic tests, including self-test facilities
   - System and report alarms
6. Electrical isolation test
7. Application logic test
8. Application software functional change test
9. System responsiveness (for example: scan time, alarm discrimination, logging and screen updates)
10. Spare capacity verification

A heat soak test may also be performed, depending on the adequacy of the routine heat soak test undertaken by the vendor as part of his standard quality control procedures. If the latter is inadequate or additional components have been added, then a heat soak test of the assembled system shall be undertaken.

5.8.3. Electrical Installation Test

All electrical systems shall be tested for insulation resistance, correct polarity and continuity. To prevent damage to low-voltage equipment, all equipment shall be disconnected at both ends of the cable prior to the cable test and reconnected prior to the functional test of the system.

Grounding shall be tested for faults and continuity.

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All terminations, glands, junction boxes and other electrical equipment enclosures shall be inspected for correct application, assembly and closure. Additionally, the system shall be checked for the following:

1. Power supply tests over stated limits.
2. Rejection of series and common mode noise on input signals in stated specifications.
3. Compatibility with the primary power supply to be used, under all load conditions. This may be part of either the factory tests or the site tests.

5.8.4. Site Acceptance Test (SAT)

The SAT shall essentially be a repeat of the FAT with the following additions:

1. The connecting wiring between distributed components shall be the actual field-installed wiring and cable.
2. The field inputs and shutdown devices shall be connected and exercised to confirm the correct connection and compatibility of the field components.
3. Actual test of interface with actual systems, i.e., DCS, etc.

It is possible that a repeat of the FAT may be the only requirement necessary to ensure that the level of performance previously confirmed still exists.

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Panels, Enclosures and Video Display Consoles

MP 32-P-05

August 1998 Draft

Scope

This Mobil Engineering Practice (MEP) covers the basic requirements for the design and installation of video display consoles (VDC) for a distributed control system (DCS) and control panels. It recognizes the evolution of control panels to cathode ray tube (CRT) terminals and microprocessor-based control systems, which constitute the preferred process-operator interface on all new installations and major upgrades. This Practice is intended to be used in conjunction with API RP 554, Section 5.

Version 0

Table of Contents

Scope 1

1. References 3

1.1. MEPS–Mobil Engineering Practices 3

1.2. API–American Petroleum Institute 3

1.3. NEMA–National Electrical Manufacturers Association 3

1.4. NFPA–National Fire Protection Association 3

2. General 4

2.1. Equipment Description 4

3. Consoles 5

3.1. Console Requirements 5

4. Control Panels 7

4.1. Control Room Installation 7

Modifications to API RP 554, Section 5 13

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1. References

The following publications form a part of this Practice. Unless otherwise specified herein, use the latest edition.

1.1. MEPS–Mobil Engineering Practices

MP 01-P-10	Blast-Resistant Buildings
MP 32-P-01	General Requirements for Instrumentation
MP 32-P-07	Safety Interlock Systems and Alarms
MP 32-P-08	Control Centers
MP 33-P-26	Electrical - Equipment Grounding and Bonding

1.2. API–American Petroleum Institute

API RP 554	Process Instrumentation and Control First Edition

1.3. NEMA–National Electrical Manufacturers Association

NEMA 250	Enclosures for Electrical Equipment (1000 Volts Maximum)

1.4. NFPA–National Fire Protection Association

NFPA 496	Standard for Purged and Pressurized Enclosures for Electrical Equipment (National Fire Codes, vol. 7)

2. General

The design, assembly and installation of video display consoles (VDC) for a distributed control system (DCS) shall be in accordance with requirements of this MEP, unless superceded by more stringent local regulations.

The references and requirements contained in MP 32-P-01, MP 32-P-07, MP 32-P-08 and MP 01-P-10 shall apply to this Practice.

2.1. Equipment Description

The following is a description of the equipment being used:

- CRT: Cathode ray tube terminals used as a process-operator interface.
- VDC: Video display consoles are CRT terminals, grouped in a cluster forming a desk-type console with provisions for a seated operator. The VDCs are installed in centralized control areas.

2.1.1. CRT Terminals

CRT terminals provide all the functions of a traditional control panel. They also provide color graphic displays for:

1. Flow and equipment configurations
2. Historical and up-to-date process data as trends
3. Control loop parameters
4. Alarms and events recording–Interactive actions by operation (e.g., start/stop, shutdown, alpha-numeric entry)
5. Dynamic process displays
6. Maintenance and troubleshooting guide (pop-up windows)

In addition, color and monochromatic hard-copy output of displays are available.

2.1.2. Control Panels

Control panels are used in remote locations for applications such as equipment-house control rooms. They are also used as local panels installed adjacent to the equipment with which the control/monitoring function is associated.

3. Consoles

VDCs use one or more CRTs for display. These have sealed keyboards to communicate with computers, distributed control systems (DCS), multiple variable temperature systems, annunciator alarm systems and individual instruments such as analyzers. The console is the primary source of information for the operation and control of the process. Normally, the minimum number of CRTs for an operating unit is three. One or more uninterruptible power supply (UPS) shall be used to distribute power to the VDCs in such a manner to prevent loss of view of the process.

3.1. Console Requirements

The VDC shall be freestanding, with a closed top and back and shall be operated from a seated position.

- It may be a simple desk type or a multi-unit with straight or wraparound styles.
- Fronts may be vertical or sloped with varying heights.
- A horizontal writing surface shall be provided.
- This console shall be purchased from the DCS vendor.
- Although most consoles have a standard configuration, they are sufficiently flexible and may be configured to specific requirements, at additional cost.
- Where a requirement exists for hard-copy recorders, pushbuttons, switches, dedicated annunciators or other panel-mount hardware, this equipment shall be mounted on the console using a standard CRT pod or bay with a metal cover plate.
- The pod may be mounted in a stacked or side-by-side configuration.
- Design of the VDCs and adjustable CRT terminals shall be ergonomic to prevent physical strain to operators.
- Location of VDCs in the control room shall provide CRTs that are glare- and reflection-free from the room lighting and/or from windows.

3.1.1. Space Requirement

- Adequate space shall be provided for access by maintenance staff, including clearance for enclosure doors as well as cable and interior component access.
- Free space around the console shall be provided for circulation of cooling air.
- Where such space is limited, the computer floor may be used as a ventilation air path, provided the concrete subfloor has been sealed and the area thoroughly cleaned.

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3.1.2. Equipment Adjustability

- Console equipment shall have height adjustments and sufficient leg room. Keyboards, CRT, mouse, trackball and auxiliary pushbuttons all shall be within the comfortable reach of a seated operator.
- Equipment shall be modular to allow for configuration to meet a process need as well as for ease of maintenance.

3.1.3. Cabling

Interconnecting cabling between cabinets, peripheral equipment and the console shall be prefabricated cable, permanently labeled at each end and used for the factory acceptance test.

Every precaution shall be exercised to:

- Use shielded wire and cable to minimize noise pickup
- Establish a grounding system recommended by the vendor
- Isolate console from radio frequencies and noise-producing equipment

3.1.4. Communication

The console shall have provisions for operators to communicate over the plant radio or communication system.

Telephone-type microphone or speaker systems shall be used, coupled to remotely located transceivers. These systems shall:

1. Permit operators to converse without disturbing users at other consoles. A common control-room speaker with a disconnect switch shall be provided.
2. Be designed to preclude console exposure to radio frequency interference (RFI).

3.1.5. Preparation for Shipping

- Preparation for shipping shall be based on console vendor recommendation.
- Fragile equipment shall be removed from the console and packed separately.
- Each item shall be suitably packed or crated to be protected from damage during shipment.
- Each item, crate or bag shall be identified by the complete purchase order number and shall be marked with the item numbers of the contents.

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3.1.6. Equipment Delivery

- As equipment is most prone to damage after delivery at the site, every effort shall be made to coordinate control room completion with delivery schedules.
- Where this is not possible, the equipment shall remain at the vendor's facility until installation can be made.
- In all cases, the VDC equipment shall be moved directly to the control room.
- On-site storage shall be avoided and equipment movements shall be minimized.

3.1.7. Direct Connections

Direct wiring connections to intermediate terminal blocks at the console may be required if recorders, pushbuttons, switches, etc., are installed on the console. Separate termination cabinets or panels are required for other direct field connections.

4. Control Panels

Control panels shall be considered for dedicated display/control or applications that are relatively simple or of insufficient content to economically justify a CRT microprocessor-based system.

4.1. Control Room Installation

If a control panel is specified for control-room use, it shall be a breakfront panel with the instrument section tilted inward, 12.5 degrees from the vertical and the upper section tilted outward, 15 degrees from the vertical (see Figure 1). Local panels shall be the conventional, vertical-face type (see Figure 3). When panels are being expanded or modified, the new panels shall match those of the existing installations.

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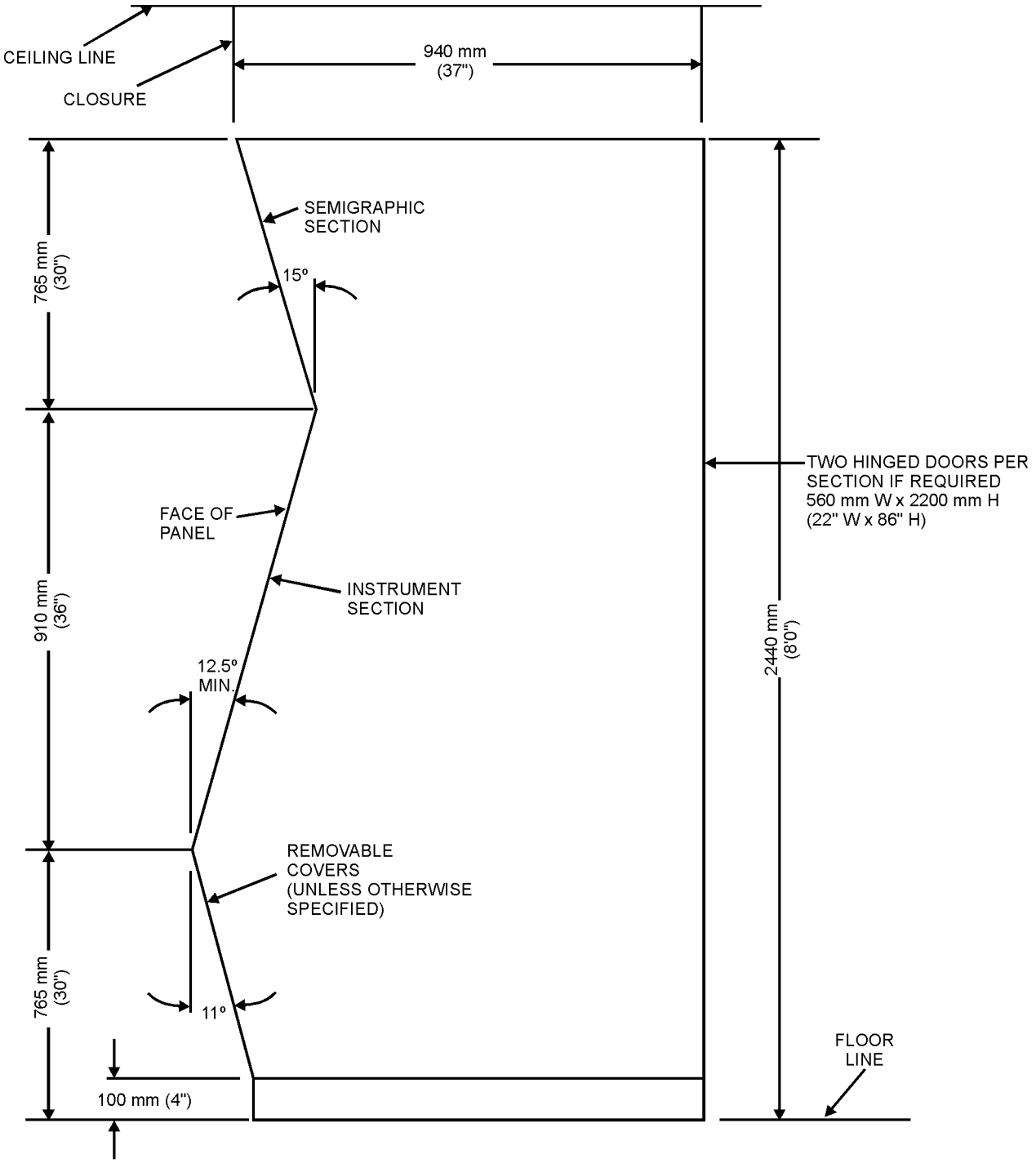

Figure 1: Control Panel for Control-Room Use

4.1.1. Panelboards

Instrument cases (sleeves) with instruments shall be shop installed in panelboards. After the panel is shop tested, the instruments shall be removed and shipped separately to the field, unless otherwise specified by Mobil.

4.1.2. Mounting in Inclined Sections

Instruments to be mounted in the inclined sections of the panel shall be provided with latches to lock the chassis in the recessed, intermediate and fully extended positions, regardless of the angle of mounting.

4.1.3. Pressurized, Heated or Air Conditioned Control Rooms

When the control room is pressurized, heated or air conditioned and electronic instruments are to be used, the control panel shall be designed to permit circulating air to enter at the lower level (bottom of intake approximately 230 mm [9 in] from floor) and to exhaust from the control panel near ceiling height.

If such an arrangement does not provide sufficient cooling of electronic instruments or components, additional circulation (muffin-type fans) shall be provided.

When the control room is not pressurized and the electrical hazardous area in which it is located requires it to be pressurized, the pressurization of the control panel and field control panels for environmental or electrical area classification shall be in accordance with NFPA 496.

The back of the control panel shall be designed so that it can be pressurized to 6 mm ($^1/_4$ in wg). Local panels, if pressurized, shall be maintained at 12 mm ($^1/_2$ in wg) pressure.

4.1.4. Preferred Process Information System

The preferred process information system for panels has a slanted semigraphic section (see Figure 1).

- The flow plan, which shall be drawn full scale, shall be arranged in a logical manner.
- The panel instruments shall be located vertically below the appropriate portion of the semigraphic.
- The approved, full-sized semigraphic drawing shall be provided to the panel vendor as major design criteria for the semigraph.

4.1.5. Walk-In Type Panel

If a walk-in type panel is specified (Figure 2), the depth of the basic panel shall be increased, creating an extension to provide for the mounting of terminal strips, power supplies, relays and so forth. Wiring troughs shall be provided inside the panel structure. These shall be of sufficient size to contain all incoming wiring, plus factory internal wiring and shall have covers or tops that snap over the troughs. Incoming field cables and instrumentation control-board wiring shall terminate at this point.

For ease of maintenance, all equipment mounted in the extension shall be readily accessible. Where this type of extension is furnished, two grounding buses shall be provided as described in API RP 554, Section 5.6.9.5, and as modified in this Practice.

A walk-in panel may be accessible from the rear (as shown in Figure 3) or from the side.

The preferred process information system and other features required for Section 4.1.4 of this MEP applies to this Section.

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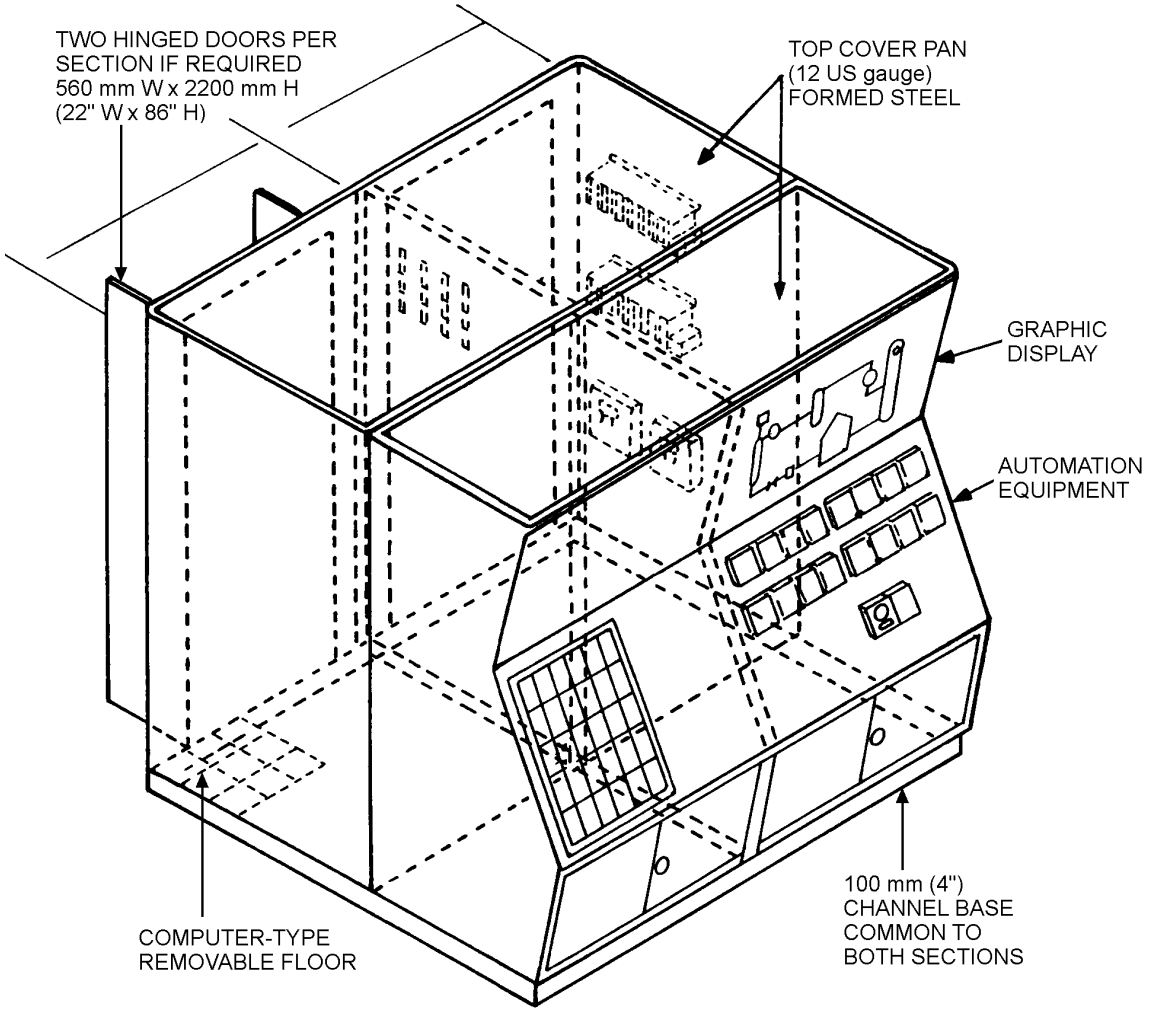

Figure 2: Walk-In Panelboard

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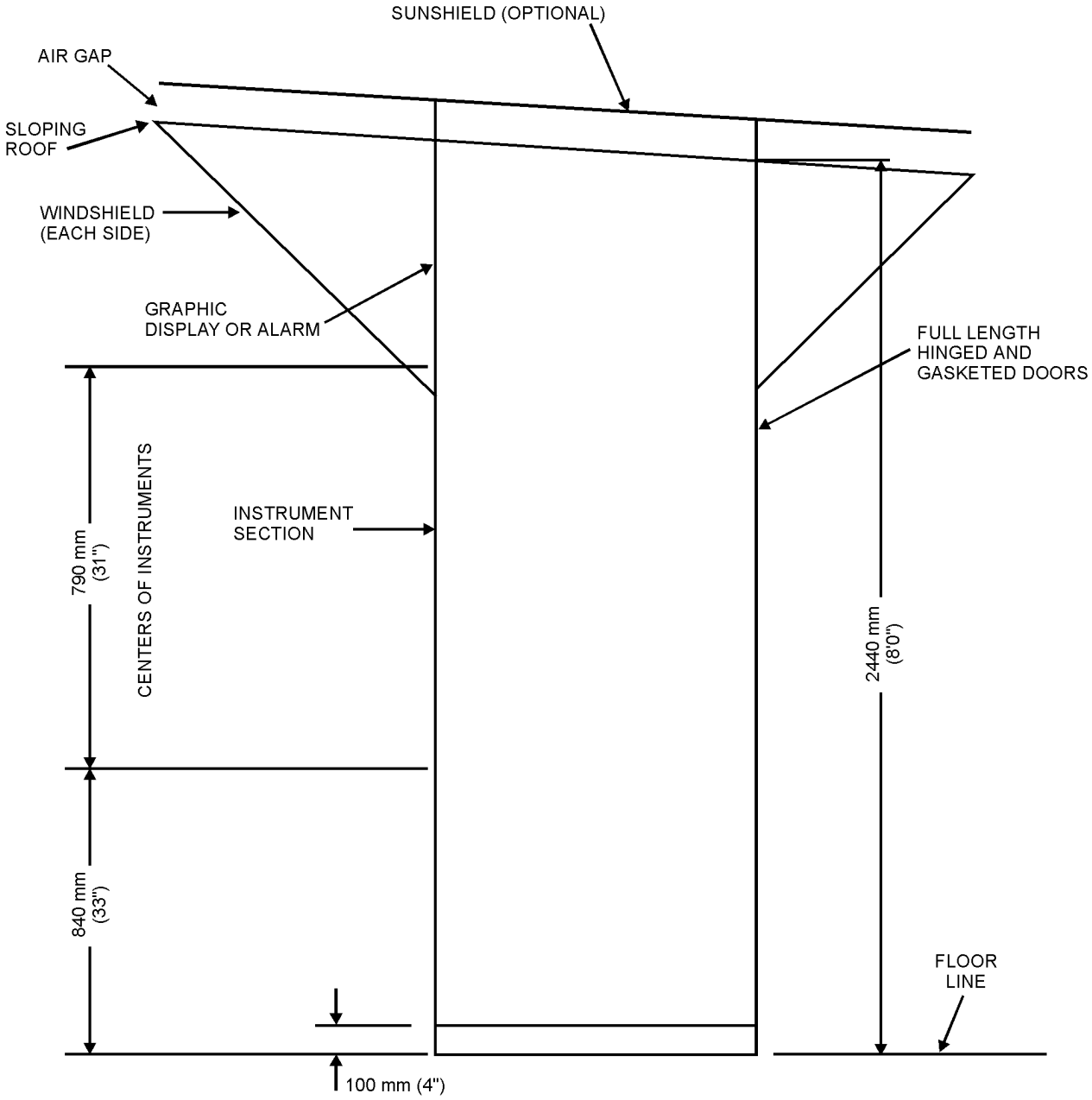

Figure 3: Local Panels

4.1.6. Free-Standing Panels

Panels for use outdoors shall be free-standing, enclosed and weather protected with sloping roofs (see Figure 3). They shall conform to NEMA 250, Type 4X.

4.1.6.1. Weather Protection

Weather protection shall include front and back weatherhoods and windshield sides.

4.1.6.2. NEMA 250 Requirements

Instruments installed on the face of the panel shall meet NEMA 250 Type 4X requirements; otherwise, covers that meet the NEMA 250, Type 4X requirements and permit instrument reading without removal shall be provided.

4.1.6.3. Illumination

Suitable illumination shall be furnished to permit maintenance and operation of all equipment (associated with the panel) in poor light or at night.

4.1.6.4. Electrical Portion

The electrical portion of the panel shall be isolated and suitable for pressurizing to 12 mm ($^1/_2$ in wg) minimum.

4.1.6.5. Pneumatic Instruments

Pneumatic instruments shall have a block-and-bleed valve within the panel.

4.1.7. Panels for Packaged Units

Panels for packaged units or systems shall be furnished in accordance with this Practice. Particular attention shall be given to the area classification of the intended location. The panel and all components furnished shall meet the requirements of applicable Mobil Practices. Only those specifications that directly pertain, in whole or in part, to the instruments, valves and related equipment to be used on a particular project shall be supplied to the vendor. A tabulation of instruments and valves, by manufacturer and types to be used, shall be supplied to the panel vendor with the project specifications.

4.1.8. Terminal Blocks

Terminal blocks shall be arranged in vertical rows with adequate separation to permit clear wiring identification. Field wiring shall be run on one side of the terminal rows and internal panel wiring on the other.

Modifications to API RP 554, Section 5

5.3.2.1. Addition: Control Panels

Normally, control-room panels shall be constructed in the conventional U-shape; however, other types of construction may be submitted for Mobil consideration.

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5.4.10. Addition: Electromagnetic Interference

Pertinent international, national and local codes for the protection of sensitive electronic equipment against extraneous electromagnetic and radio frequency radiation shall be specified. Examples are:

- IEC 801-2 and 801-3: Electromagnetic Compatibility for Industrial Process Measurement and Control Equipment
- EN-50081-1: Generic Emissions Standard Part 1 for Residential, Commercial and Light Industry
- EN-50082-1: Generic Immunity Standard Part 1 for Residential, Commercial and Light Industry
- EN-50081-2: Generic Emissions Standard Part 2–Industrial
- EN-50082-2: Generic Immunity Standard Part 2–Industrial
- United Kingdom EMC Regulations Statutory Instrument No. 2372 of 1992
- It is mandatory for almost all electrical and electronic equipment supplied or installed in European Economic Community countries to carry European conformity marking (CE) for conformity with Council Directive 89-336-EEC, July 3, 1989 on the approximation of the laws of the member states relating to electromagnetic compatibility.

5.6.6. Addition: Instrument Arrangements

The mounting of instruments behind the panel shall permit easy access to each one for adjustment in place or for complete removal without obstruction by other instruments or panel structural members. Switches and auxiliaries shall be mounted in an unobtrusive manner. Doors on the back of the panelboards and doors on wall-mounted panels or on equipment facing the clearance aisles shall open without obstruction and shall give free access to the interior of the panels and equipment. These doors shall be removable by lifting them off the hinges.

All miniature recorders and other instruments that require manual adjustments shall be located with their centerlines no higher than 1630 mm (64 in) and no lower than 840 mm (33 in) above the floor.

With miniature instruments, a high-density arrangement shall be used. The miniature instruments shall be furnished in standard racks. No more than 10 instruments per rack (pack) shall be furnished without the express approval of Mobil. All racks shall be pre-wired and/or pre-tubed with readily accessible tubing or terminal blocks. All wiring at terminal blocks and tubing terminations shall be tagged with permanent sleeve-type tags. All instruments shall be arranged as closely as practical in a logical and orderly manner following the piping and instrument diagrams.

Front-panel-mounted instruments shall be identified with nameplates showing instrument number and service on both the front and back of the panel. Back-panel-mounted

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instruments shall be identified with a single nameplate showing only the instrument number.

5.6.8. Addition: Fabrication

Blank or partially filled panels shall be provided with spare electrical switches and/or air-header valves consistent with the initial installation. The need for blank or partially filled panels shall be developed during the design phase. All unused cutouts in the panel or console require coverplates. The coverplate shall be supplied by the manufacturer of the device or panel fabricator for the cutout. Blank panels or partial panel space equal to 15 percent of a normally occupied instrument area are considered minimum. This percentage of spare capacity shall be applied to all ancillaries, including back-panel space.

5.6.5.3. Addition: Semigraphic Panels

The graphic section shall be laid out to present sequentially the same geographic orientation as in the actual units. For example, if three parallel units are numbered 1–3 (left to right) when viewed from the control room (or other designated point), they shall be represented on the panel as Units 1–3, left to right. (Note: Full graphic panels shall not be used.)

As an alternative, mosaic tile types or a drawing or print mounted under glass or clear plastic may be used. The simplified flow plan for semigraphic panels shall use Mylar colored tapes to depict all lines and equipment. It shall be covered with plate glass or an approved plastic substitute. The semigraph shall be attached to the panel steel by a frame consisting of metal tracks that run the full length of the diagram. The tracks shall be bolted to the panel steel. Both glass and diagram shall be in sections to permit easy removal to incorporate changes in the diagram.

Instruments shall be arranged in the control panel, located below the semigraph, in a logical and orderly manner. They shall have a color-coded disk or nameplate to correspond with their location on the display immediately above. For example, if the temperature point is shown on a vessel by a red square, the corresponding instrument shall have a red disk or name tag. A recognized color scheme shall be maintained: red graphic display symbols and red nameplates for temperature instruments, blue for flow, yellow for pressure, green for level and white for analyzers.

If alarm lights are mounted behind the graphic representation for annunciating purposes, provision shall be made to permit the easy repositioning of lights within a 2 m (80 in) radius to correspond with diagram revisions.

Safeguards shall be provided to maintain proper operation and protection of panel mounted instruments in hot and cold environments. Instrument vendor ambient temperature specifications shall be followed

5.6.8.2. Addition: Field Panels

In hot, humid and corrosive environments, special considerations recommended for field-mounted panels are as follows:

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1. Use white painted panels, double-skinned construction (excluding panel face instrument section) with polyurethane insulation to reduce absorption of solar radiation.
2. Use a sun shield and air gap on top of panel.
3. Use air conditioning or vortex cooling to maintain a moisture-free panel internal temperature environment for electronic instruments.
4. Use fiberglass panels to eliminate corrosion caused by condensation or chemicals.
5. Use non-hygroscopic, non-nutrient materials as practicable to reduce fungus growth susceptibility.

All local panels shall have suitable front guarded, explosion-proof light and interior lighting.

5.6.9.2. Addition and Modification: Electrical Supply

Electrical supply to an instrument panel shall be limited to 2-wire, 120V (or 3-wire 240V), grounded, single-phase alternating current (AC), depending on the standard AC voltage for the geographical area. The wiring shall be clearly labeled. Any direct current (DC) electric wiring, such as 12V, 24V or 48V, shall be connected to a separate terminal block and shall be labeled. AC, DC, intrinsically safe (IS) or nonincendive circuits shall be physically separated and insulated from each other. IS circuits shall be color coded (blue jacket) and run in separate wireways to separate terminals. DC power supply used for IS and nonincendive circuits shall not be used as a DC power source for other circuits that are not intrinsically safe or nonincendive.

As a minimum, check design requirements for dual power supply, UPS, non-UPS, percent fluctuation of the power supply voltage and frequency for improved reliability of the operation. It is recommended that 120 and/or 240 volt power outlets are installed. Ensure surge protection requirements are complied with where required.

5.6.9.3. Addition and Modification: Disconnect Switches

Two-pole disconnect switches shall be used on the power supply to instruments, arranged to disconnect both leads. Two-pole, fused disconnect switches may be used with Mobil approval.

Each 120 or 240 volt, AC powered electronic instrument shall be provided with a separate power disconnects.

5.6.9.4. Addition: Terminal Blocks

Use a vertical terminal strip with individual clip-on modules, mounted on a standard rail and equipped with shrouded-screw test points. These terminals shall be readily accessible, provided with identification and suitable for easy maintenance with a screwdriver or an approved wiring tool. All terminations shall be either the compressed, crimped, lugged or pin type. Terminal blocks and/or connections shall be single level (not tiered). Where the instrument vendor advises that the wires shall run directly to the receiving instrument, no terminal blocks are permitted (e.g., some types of analyzers, T/C extension wire).

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5.6.9.5. Modification: Panel Board Grounding

Each frame section shall be provided with three bare, soft copper, solid bar, grounding buses, each at least 6 x 25 mm ($^1/_4$ x 1 in). The first bus shall be a non-IS instrument signal ground; the second bus shall be an IS signal ground; the third bus shall be an equipment ground. The ends of the buses shall be arranged so that when all sections of the panelboard are in place, each grounding bus shall be one continuous system. After installation, the grounding buses shall be bonded to the site instrument-grounding system at only one point. The grounding buses shall remain isolated within the panel and until bonded at the site instrument grounding system (see MP 33-P-26). Instrument cases shall not rely on grounding through the steel of the panel.

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Control Valves

EPT 05-T-07

November 1992 Draft

Version 0

Table of Contents

1. Scope 6

2. References 6

2.1. MEPs–Mobil Engineering Practices 6

2.2. CHILTON–Chilton 6

2.3. ISA–Instrument Society of America 6

3. Principles of Operation 6

3.1. Globe-Shaped Valves 7

3.2. Angle Valves and Chokes 11

3.3. Butterfly Valves 13

3.4. Ball Valves 14

3.5. Plug Valves 15

3.6. Gate Valves 16

3.7. Specialty Valves 16

4. Valve Selection 17

4.1. Flow Characteristics 17

4.2. Valve Body 23

4.3. Summary of Control Considerations 31

4.4. Materials Considerations 32

5. Actuators 38

5.1. Pneumatic Diaphragm 38

5.2. Piston Actuators 44

5.3. Electric Actuators 46

5.4. Positioners and Boosters 46

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5.5. Transducers 50

6. Installation 51

6.1. Connections 51

6.2. Bypass Valves 52

6.3. Location 52

7. Control Valve Sizing 53

7.1. General 53

7.2. Liquids 54

7.3. Gas 55

7.4. Two-Phase Flow 55

7.5. Noise 55

Table of Figures

Figure 1: A Top-Guided, Single Port Globe Valve (Courtesy of Valtek, Inc.) 8

Figure 2: A Top and Bottom Guided, Double Port Globe Valve (with Permission of Masoneilan North American Operations. Dresser Valve & Controls Division, Dresser Industries, Inc.) 9

Figure 3A: Cage Guided Globe Valve: Standard Construction (Courtesy of Fisher Controls).....10

Figure 3B: Cage Guided Globe Valve: Optional Cage Design with Multiple Piston Rings (Courtesy of Fisher Controls) 10

Figure 3C: Cage Guided Globe Valve: Optional Cage Design with Restricted Trim (Courtesy of Fisher Controls) 11

Figure 4: An Angle Valve (Courtesy of Willis Division of Smith Industries) 12

Figure 5: A Butterfly Valve (Courtesy of Fisher Controls).....14

Figure 6: A Ball Valve (Courtesy of WKM) 15

Figure 7: A Rotary Eccentric Plug Valve (with Permission of Masoneilan North American Operations, Dresser Valve and Controls Division, Dresser Industries, Inc.) 16

Figure 8: Globe Valve Plugs for the Three Main Inherent Characteristics (Courtesy of Valtek Inc.).....18

Table 2: Class VI Seat Leakage Allowable (In accordance with ANSI B16.104-1976) 22

Figure 9: Three-Way Skirt-Guided Globe Valve: (a) External View Showing Position of Pneumatic Actuator; (b) Design with Quick Opening Valve Plug; (c) Design with V-Port Valve Plug (Courtesy of Fisher Controls) 25

Figure 10: Cage-Guided Three-Way Globe Valve: (a) Standard Design; (b) Optional Design; (c) Cutaway Views of Both Designs Showing Flow Direction with Variations in Plug Position (Courtesy of Fisher Controls).....27

Figure 11: Typical Sliding Slab Gate Valve (Courtesy of Chilton Instrument Engineers' Handbook).....29

Figure 12: A Saunders Diaphragm Valve (Courtesy of Masoneilan Division, McGraw-Edison).....30

Figure 13: Automatic Compression Packing (Courtesy of Fisher Controls) 36

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Figure 14: Manual Compression Packing (Courtesy of Fisher Controls).....37

Figure 15: Packing Lubricator and Isolation Valve (Courtesy of Fisher Controls).....37

Figure 16A and B: Diaphragm Actuators: (a) Actuators for Rotary Stem Valve Showing Lever Arm Linkage; (b) Rotary Stem Valve Actuator with Adjustable Spring (Courtesy of Fisher Controls).....38

Figure 16C and D: Diaphragm Actuators: (c) Vertically Adjustable Valve Stem Actuator with Pneumatic Inlet Below Diaphragm; (d) Vertically Adjustable Valve Stem Actuator with Pneumatic Inlet Above Diaphragm (Courtesy of Fisher Controls)39

Figure 17: A Piston Actuator (Courtesy of Valtek, Inc.) 45

Figure 18: Geared Electric Actuator for a Rotary Stem Valve (Courtesy of Limitorque) 46

Figure 19A Valve Positioners: Schematic Showing Pressure Pathways (Courtesy of Moore Products Co., Spring House, PA) 47

Figure 19B: Valve Positioners: Valve Positioner and Placement on Actuator (Courtesy of Moore Products Co., Spring House, PA) 48

Figure 20: Valve Booster: (a) Schematic of High Accuracy, Low Capacity Booster; (b) High Capacity Booster; (c) Typical Circuit with Booster Valve Used to Improve Stroking Speed of Large Diaphragm Valve (Courtesy of Moore Products Co., Spring House, PA) 49

Figure 21A Antinoise Valves: Typical Cage-Type Valve (Courtesy of Fisher Controls)58

Figure 21B: Antinoise Valves: Whisper Trim I Trim (Courtesy of Fisher Controls) ..58

Figure 21C: Antinoise Valves: Alternative Whisper Trim III Trim (Courtesy of Fisher Controls).....59

Figure 21D: Antinoise Valves: Flow Path for Cage (Courtesy of Fisher Controls.....59

Figure 22: Diffuser: (a) In-Line Diffuser; (b) Control Valve with In-Line Diffuser (Courtesy of Fisher Controls) 60

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1. Scope

The basic principles of control valve operation are fairly simple and easy to understand. This tutorial covers how to select the proper type of valve, the suitable materials, and an appropriate size. Difficult applications that are regularly encountered in oil and gas processing, such as cavitation and aerodynamic noise, are discussed. Formulas used for sizing valves are referenced.

2. References

The following industry publications shall be considered a part of this EPT. Refer to the latest editions unless otherwise specified herein.

2.1. MEPs–Mobil Engineering Practices

MP 32-P-04	Control Valves and Actuators

2.2. CHILTON–Chilton

CHILTON	Instruments Engineer's Handbook (2 Volumes) - Process Measurement and Process Control

2.3. ISA–Instrument Society of America

ISA S75.01	Flow Equations for Sizing Control Valves R(1995)
ISA S75.05	Control Valve Terminology Errata - 1983
ISA S75.17	Control Valve Aerodynamic Noise Prediction
ISA	Control Valve Selection and Sizing (Les Driskell 1983)

3. Principles of Operation

There are two basic control modes for control valves: on/off and modulating control. On/off control is primarily for batch processes such as cycling of desiccant dryers, snap-acting level control, or safety shutdown valves. Modulating control is the primary mode and is used to control process functions such as level, pressure, temperature, flow, etc. Control valves are manufactured in several body styles. Each of these designs is appropriate for use in some circumstances, and often more than

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one type may be satisfactory. Improper valve selection can often cause considerable expense due to poor control of process.

3.1. Globe-Shaped Valves

3.1.1.

Globe type valves are the most commonly used valve for modulating control in the process industry. This design lends itself to variations of internal geometry that make them useful in a wide variety of applications. Globe control valves are available with body sizes as small as 13 mm ($^1/_2$ in) and as large as 400 mm (16 in).

3.1.2.

Figure 1 shows a typical globe valve. The identifying characteristic is that a plug moves vertically so that flow is regulated by the area between the plug and a circular seat. The plug and the seat are machined and sometimes honed to form a good seal. Resilient material can be used in order for the seat to form an even better seal. Various body geometries and plug shapes give different flowing characteristics.

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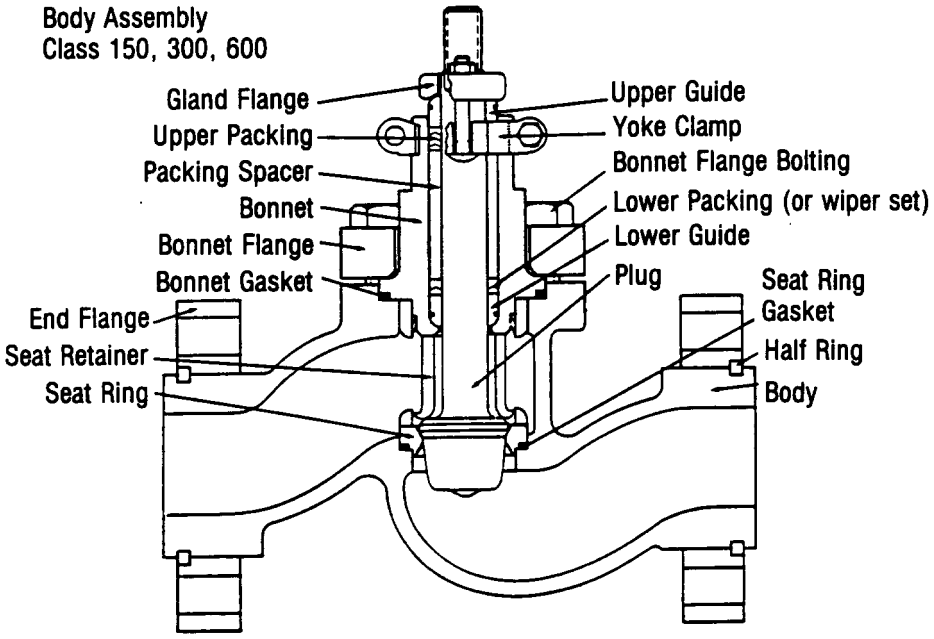

Figure 1: A Top-Guided, Single Port Globe Valve (Courtesy of Valtek, Inc.)

3.1.3.

The plug is held in position by the stem. The stem is moved up or down to provide throttling by opening or closing the flow area of the valve. The stem slides through guides that keep it aligned with the seat. A single guide in the top-works of the valve is adequate for many applications. Some designs which use heavy plugs and small stems incorporate a guide in the top-works and another in the bottom of the body; these are known as top-and-bottom-guided. Figure 2 shows a top-and- bottom-guided globe valve. The third important type of plug alignment is cage guiding, in which the plug travels inside a machined sleeve and closes holes in the sleeve to control flow. Figure 3 shows a cage guided globe valve. Finally, skirts may be added to the plug so that the port acts as a guide. This plug alignment is called port or skirt guiding.

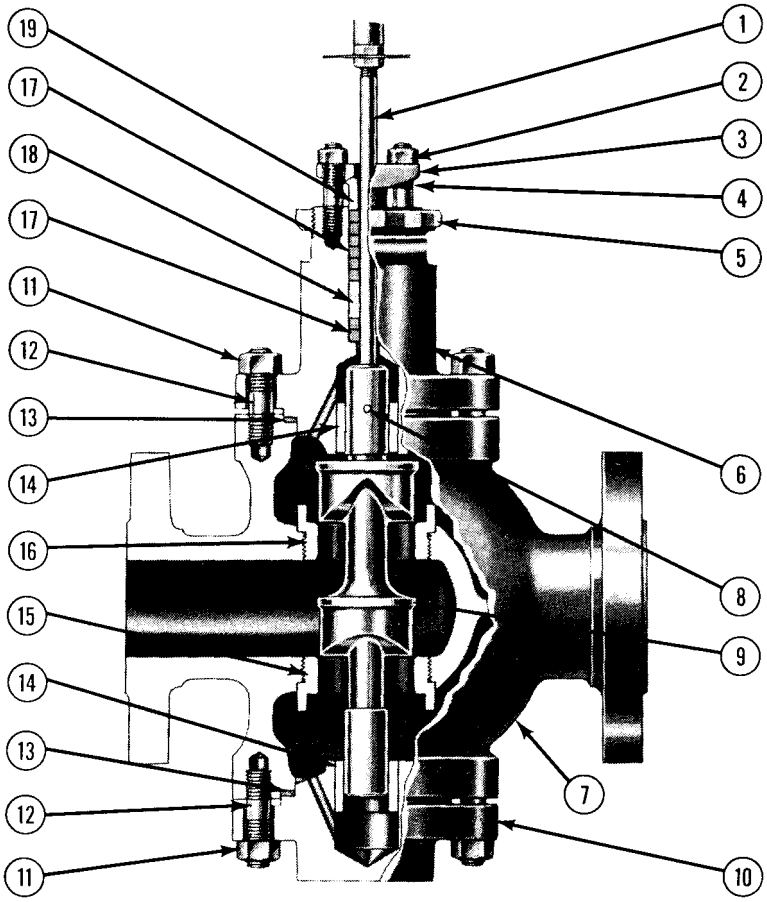

Figure 2: A Top and Bottom Guided, Double Port Globe Valve (with Permission of Masoneilan North American Operations. Dresser Valve & Controls Division, Dresser Industries, Inc.)

1	Valve Plug Stem	**11**	Lower Seat Ring
2	Packing Flange Nut	**12**	Blind Flange
3	Packing Flange	**13**	Valve Body Gasket
4	Packing Flange Stud	**14**	Valve Plug
5	Packing	**15**	Plug Pin
6	Packing Spacer	**16**	Guide Bushing
7	Valve Body Stud	**17**	Bonnet
8	Valve Body Stud Nut	**18**	Drive Nut
9	Body	**19**	Packing Follower
10	Upper Seat Ring		

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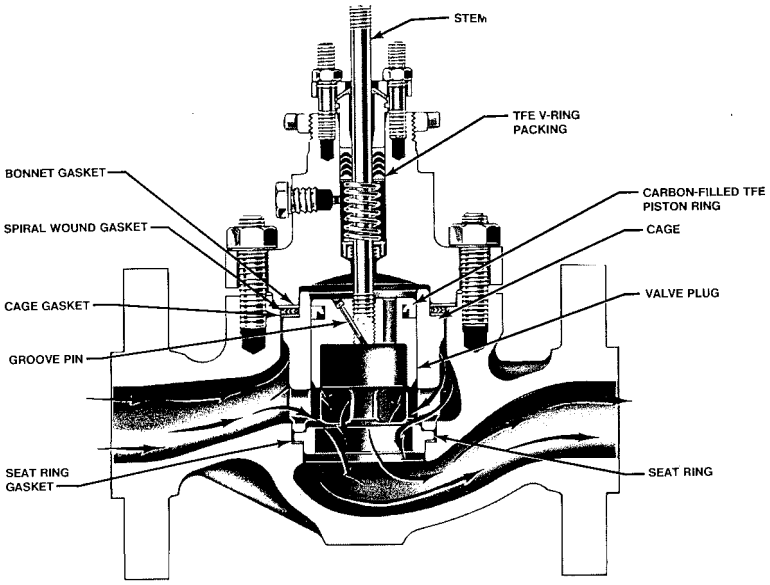


Figure 3A: Cage Guided Globe Valve: Standard Construction (Courtesy of Fisher Controls)

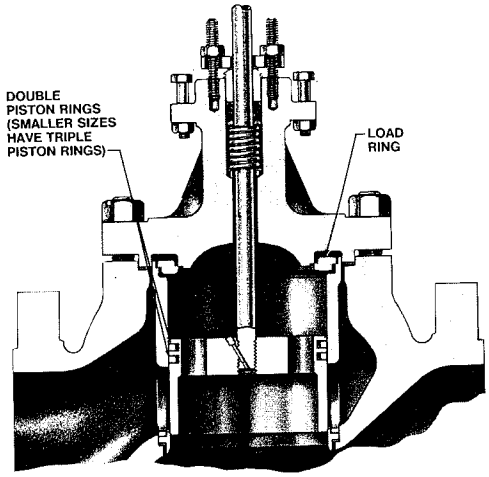


Figure 3B: Cage Guided Globe Valve: Optional Cage Design with Multiple Piston Rings (Courtesy of Fisher Controls)

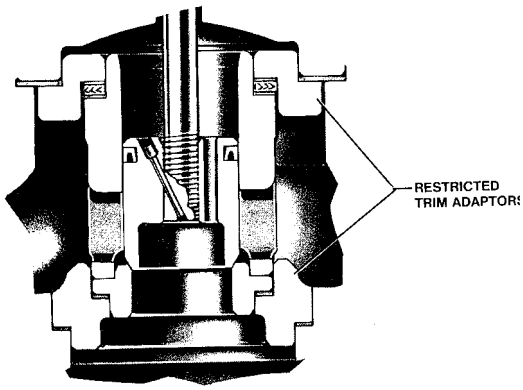


Figure 3C: Cage Guided Globe Valve: Optional Cage Design with Restricted Trim (Courtesy of Fisher Controls)

3.1.4.

The number of ports in a globe valve refers to the number of orifices through which flow may pass. Most valves are either single- or double-ported valves. Cage-guided valves are considered single-ported, even though there are usually several passages through the cage.

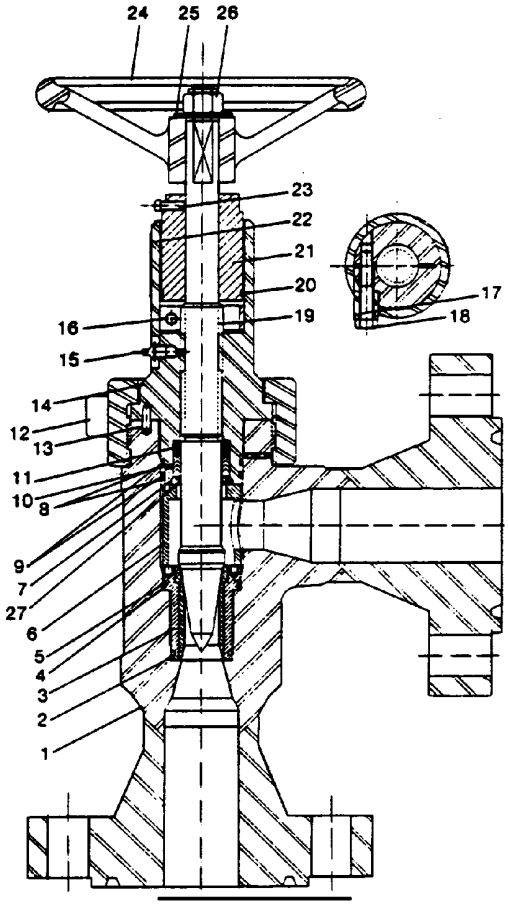
3.1.5.

The trim of a valve consists of the internal parts that come in contact with the fluid - the stem, guide, plug, and seat. Most valves are designed so that the trim parts can be changed to renew a worn valve or alter the flowing characteristics.

3.2. Angle Valves and Chokes

3.2.1.

Figure 4 shows a variation of a globe valve in which the flow direction of the outlet is 90 degrees from the flow direction of the inlet. Angle valves are sometimes used for piping convenience; they have good flow characteristics in either direction.



KEY NO.	DESCRIPTION
1	Body
*2	O-Ring for Seat
*3	Seat Assembly
	.25" .50" .75" 1.00" Trim Sizes
*4	Back-Up Ring for Seat
*5	O-Ring for Seat
6	Cage
7	Spring Pin
*8	O-Ring for Bonnet
*9	Back-Up Ring for Bonnet
*10	Packing Set
11	Stem Guide
12	Body Flange
13	Groove Pin
14	Bonnet
15	Grease Fitting
16	Stem Clamp
17	Clamp Spacer
18	Clamp Screw
*19	Stem
	.25" .50" .75" 1.00" Trim Sizes
*20	O-Ring for Position Indicator
21	Position Indicator .25" .50" Calibrated for .75" Trim Sizes 1.00"
22	Identification Label
23	Set Screw
24	Handwheel
25	Washer
26	Lock Nut
27	Back Seat Adapter

Figure 4: An Angle Valve (Courtesy of Willis Division of Smith Industries)

3.2.2.

A major use for angle valves is for large pressure drops where cavitation is possible. For this application, the flow shall be into the side and out away from the stem. While cavitation damage may occur, it will be mostly to the valve outlet and downstream piping rather than to the plug and stem. Variable choke valves are a form of angle valve specially designed for this application; they feature a hardened, replaceable seat (or bean) which extends to the outlet.

3.2.3.

Adjustable chokes have a variable orifice and are used to control flow or pressure drop when there are a variety of conditions to be met. A fixed choke is used when flow shall be limited but where other controlling devices adjust the actual rate.

3.2.4.

See Section 4.7 of the Chilton Process Control Handbook for more details.

3.3. Butterfly Valves

3.3.1.

Butterfly valves have a round disk for regulating flow, as shown in Figure 5. The disk is attached to a shaft, one end of which rests in a bushing, with the other end brought out through a seal assembly for actuator attachment. The disk can be rotated perpendicular to the pipe to stop flow, parallel to the pipe to maximize flow, or in between to regulate flow. Manufacturers offer variations of the basic disk shape that enhance throttling characteristics, provide shutoff capabilities, or minimize the required torque.

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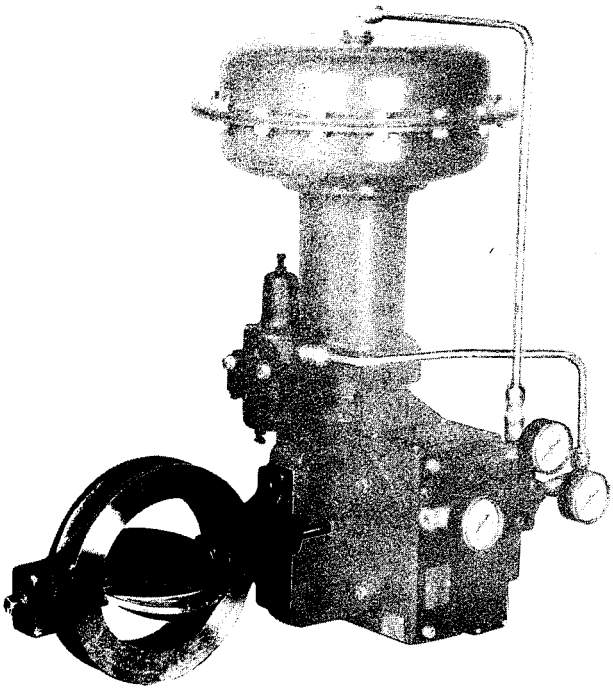

Figure 5: A Butterfly Valve (Courtesy of Fisher Controls)

3.3.2.

Butterfly valves are usually constructed in wafer fashion to fit between two ordinary piping flanges with long bolts. Sometimes they are constructed with bolt lugs to give more support and rigidity. The absence of flanges and body castings keeps the price of butterfly valves below that of other types of valves of equivalent size. However, care shall be taken to assure the adjacent piping is such that the disk does not bind in the flanges through its range of motion. Butterfly valves are available in sizes from 50 mm (2 in) to extremely large. While the cost of smaller sizes is similar to that of other types of valves, butterfly valves become more economical as size increases.

3.3.3.

Refer to Section 4.4 of the Chilton Process Control Handbook for more details.

3.4. Ball Valves

Ball valves feature a spherical plug which is rotated within a similarly shaped chamber, as shown in Figure 6. The ball is bored with a hole which can be lined up with the pipe openings, perpendicular to the openings, or somewhere in between. If the hole through the ball is the same size as the inside diameter of the pipe, it is called full port or full bore.

If the hole is smaller than the inside diameter of the pipe, it is called reduced port or reduced bore. Full port ball valves are used when an object (such as a pipeline pig or scraper) shall pass through, or where even a small pressure drop cannot be tolerated. Reduced port valves have bodies that are tapered between the pipe and the ball so that the pressure drop is small; they are satisfactory in most applications. A "regular port" ball valve has a reduced port. If a full port is desired, it shall be specified. Refer to Section 4.3 of the Chilton Process Control Handbook for more information.

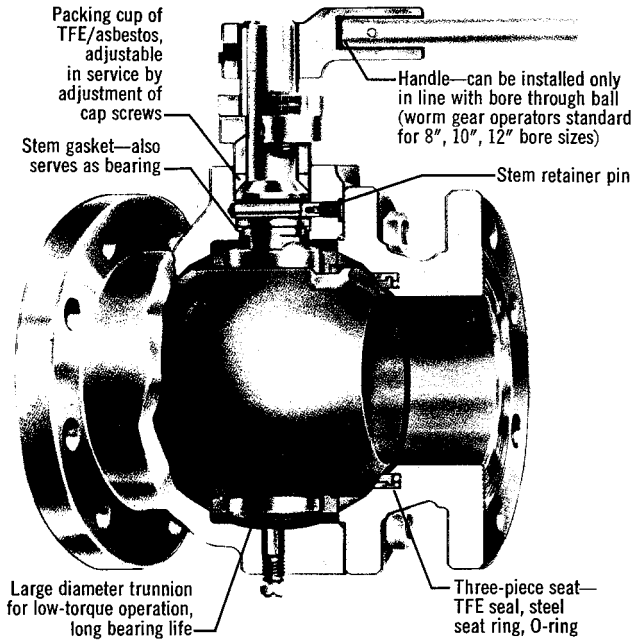
Packing cup of TFE/asbestos, adjustable in service by adjustment of cap screws
Stem gasket—also serves as bearing
Handle—can be installed only in line with bore through ball (worm gear operators standard for 8″, 10″, 12″ bore sizes)
Stem retainer pin
Large diameter trunnion for low-torque operation, long bearing life
Three-piece seat—TFE seal, steel seat ring, O-ring

Figure 6: A Ball Valve (Courtesy of WKM)

3.5. Plug Valves

The plug valve is among the oldest valve designs known. It is a form of quarter turn valve. The typical "V" shape of the plug provides a quick-opening and tight shutoff, with leak-proof closure up to approximately 69,000 kPa, (10,000 psig). Figure 7 shows a typical eccentric plug valve. Refer to Section 4.10 of the Chilton Process Control Handbook for more details.

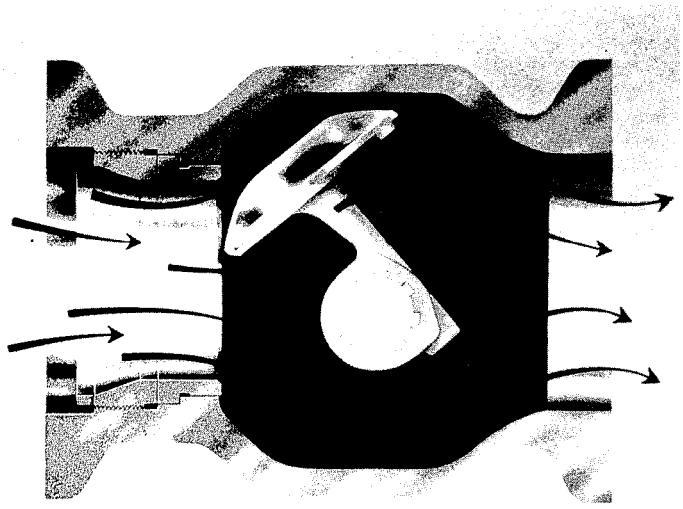

Figure 7: A Rotary Eccentric Plug Valve (with Permission of Masoneilan North American Operations, Dresser Valve and Controls Division, Dresser Industries, Inc.)

3.6. Gate Valves

The gate valve, commonly known as a rising stem valve, employs some form of plate which is used to cut off the flow. Refer to Section 4.12 of the Chilton Process Control Handbook for more details.

3.7. Specialty Valves

Several manufacturers have products that do not exactly fit any of the above categories, yet are suitable for many applications. In general, these are special designs of the above type valves with the purpose of providing valves which can handle large pressure drops with minimum noise and cavitation. Some of the valves can handle the presence of some solids (e.g., sand) in the process flow. Refer to Chapter 4 of the Chilton Process Control Handbook and the ISA "Control Valve Selection and Sizing" handbook for detailed specifics on control valves.

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4. Valve Selection

4.1. Flow Characteristics

The inherent flow characteristic of a control valve is the relationship of the flow rate through the valve to the valve travel while a constant pressure drop is maintained across the valve body. The installed flow characteristic is the relationship of the flow rate to valve travel, as the pressure drop across the valve varies as a result of the many factors involved in the process. The objective in choosing an inherent flow characteristic for the valve is to make the installed flow characteristic as nearly linear as possible. Figure 8 shows globe valve plugs for the three main inherent flow characteristics.

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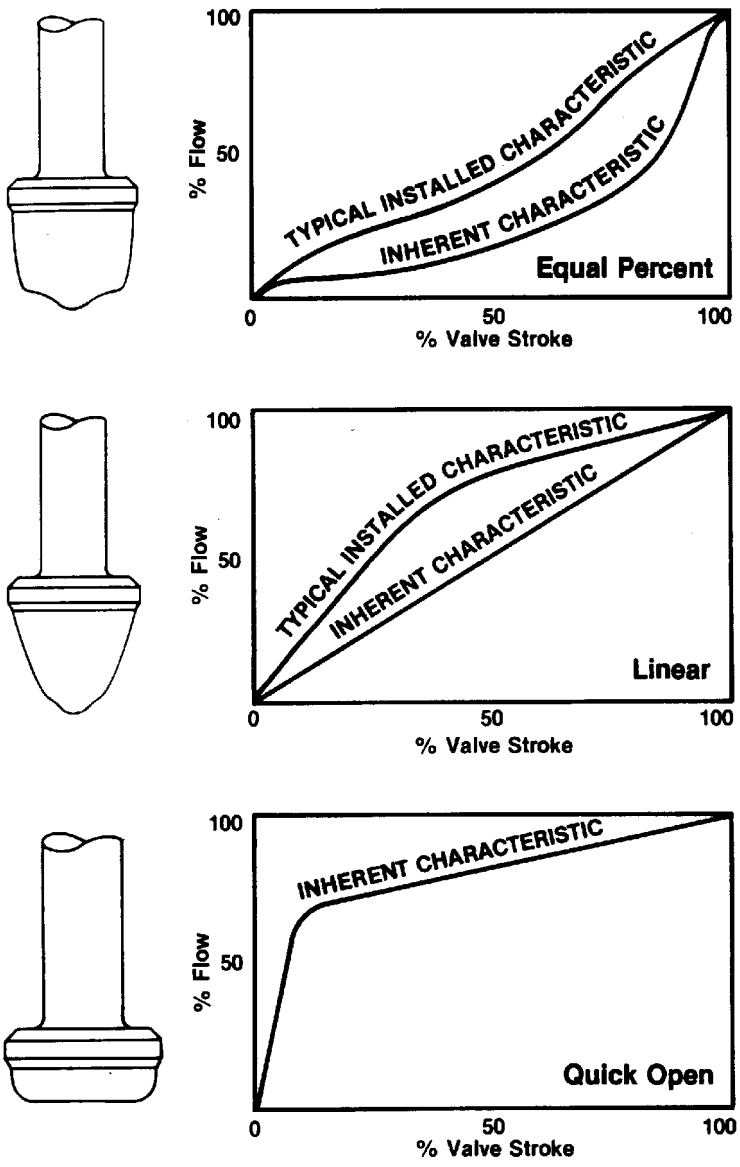

Figure 8: Globe Valve Plugs for the Three Main Inherent Characteristics (Courtesy of Valtek Inc.)

4.1.1. Linear

With the linear inherent characteristic, the flow is directly proportional to the valve stem movement. That is to say, at 50 percent stem movement, the C_v (basic valve flow coefficient) is 50 percent of maximum, and at 80 percent of movement, the C_v is 80 percent of maximum. Linear valves are best when the pressure drop across the valve is fairly constant, no matter what the flow

rate. Linear trim is usually used for flow control, liquid pressure control, and modulating liquid level control.

4.1.2. Equal Percentage

The equal percentage inherent characteristic means that the C_v changes in proportion to the percentage increment of the valve travel. This characteristic means that valve movements near the seat cause relatively small C_v changes, while valve movements near the wide open position cause large C_v changes. This characteristic is useful when the available pressure drop decreases with increased flow, or when the effect on the process is diminished as the flow rate increases. Gas pressure control loops and temperature loops usually fall into this category.

4.1.3. Quick Opening

The quick opening inherent characteristic is that in which the flow rate changes more rapidly at low valve travel than when the valve is nearly open. This characteristic is useful when a rapid rise to near maximum flow is needed, such as in applications in which it is necessary to respond quickly to pressure surges and in on/off level control. This characteristic could be useful for a liquid control valve in situations in which solids may be present. A simple disk covering a flow nozzle has this characteristic. Quick opening valves are commonly used for self- actuated pressure regulators, relief valves, and on/off applications.

4.1.4. Fluid Flow Direction

1. Valve manufacturers usually recommend a direction for fluid flow through their product that is often indicated by an arrow that is cast on the body. Most valve designs have better flow characteristics with the flow going through the port toward the stem, thus providing an opening force on the plug. General exceptions are those valves in which liquid cavitation or flashing can be anticipated. Cavitation and flashing cause increased wear on valve parts downstream of the port, so it is usually better to have the flow direction be away from the stem and stem guides. By so doing, most of the wear or erosion will affect the plug seat and lower body, which are more substantial. Also, the flow is inward at the seat, which causes the fluid to impinge on itself to some extent.

2. These general guidelines can be used to help decide between the different designs that are available from a manufacturer, or they can be used to choose a flow direction if the manufacturer allows flow in either direction. These guidelines are not intended to encourage disregard of the manufacturer's recommended flow direction.

4.1.5. Seat Leakage Classifications

1. Some applications require the control valve to be completely closed against the process pressure when certain conditions occur. When this is

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true, the amount of fluid that leaks past the valve while it is closed is often important for process or metering criteria. Leakage can also be detrimental to the valve because erosion damage is much greater when the clearance between the plug and seat is small. For these reasons, a valve with low leakage (or tight shutoff) shall be selected for on/off or other service when the valve will be expected to seal against significant differential pressure while closed. On the other hand, if the valve will be throttling when in service, tight shutoff ability shall add to the cost without any offsetting advantage.

2. ANSI standard B16.104-1976 defines six leakage classes. The definitions for these classes are shown in Table 1. Allowable leakage rates for Class VI valves are shown in Table 2. Typical classes for different types of valves are shown in Table 3. Standard leakage classification valves are satisfactory for applications with continuous throttling. For applications such as separator dump valves, which cycle between fully open and closed, a valve with a class IV or better rating shall be selected. If the differential pressure is more than about 2750 kPa (400 psi), a class V or VI shutoff is needed to prevent excessive erosion. Class VI valves shall be used for bypass or diverter valves in measurement systems, or in other applications where any small leakage is a problem.

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Table 1: Control Valve Seat Leakage Classifications (In Accordance with ANSI B16.104-1976)

Leakage Class Designation	Maximum Leakage Allowable	Test Medium	Test Pressures	Testing Procedures Required for Established Rating
I	—	—	—	No test required provided user and supplier so agree.
II	0.5 percent of rates capacity	Air or water at 10 to 52°C (50 to 125°F)	45 to 60 psig or max. operating differential, whichever is lower	Pressure applied to valve inlet, with outlet open to atmosphere or connected to a low head loss measuring device, full normal closing thrust provided by actuator.
III	0.1 percent of rated capacity	As above	As above	As above
IV	0.01 percent of rated capacity	As above	As above	As above
V	0.0005 ml per minute of water per inch of port diameter per psi differential	Water at 10 to 52°C (50 to 125°F)	Max. service pressure drop across valve plug, not to exceed ANSI body rating. (100 psi pressure drop minimum)	Pressure applied to valve inlet after filling entire body cavity and connected piping with water and stroking valve plug closed. Use net specified max. actuator thrust, but no more, even if available during test. Allow time for leakage flow to stabilize.
VI	Not to exceed amounts shown in following table based on port diameter	Air or Nitrogen at 10 to 52°C (50 to 125°F)	50 psig or max. rated differential paressure across valve plug, whichever is lower	Actuator shall be adjusted to operating conditions specified with full normal closing thrust applied to valve plug seat. Allow time for leakage flow to stablize and use suitable measuring device.

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Table 2: Class VI Seat Leakage Allowable (In accordance with ANSI B16.104-1976)

NOMINAL PORT DIAMETER		LEAK RATE	
Inches	Millimeters	ml per Minute	Bubbles Per Minute*
1	25	0.15	1
$1^1/_2$	38	0.30	2
2	51	0.45	3
$2^1/_2$	64	0.60	4
3	76	0.90	6
4	102	1.70	11
6	152	4.00	27
8	203	6.75	45

* Bubbles per minute as tabulated are an easily measured suggested alternative based on a suitable calibrated measuring device such as a $^1/_4$-inch OD x 0.032-inch wall tube submerged in water to a depth of $^1/_8$-inch to $^1/_4$-inch. The tube end shall be cut square and smooth with no chamfers or burrs and the tube axis shall be perpendicular to the surface of the water. Other apparatus may be constructed and the number of bubbles per minute may vary from these shown, as long as they correctly indicate the flow in ml per minute.

Table 3: Typical Classes for Different Types of Valves

	Leakage Class Designation
Butterfly valves with metal seats	I
Cage-guided valves with standard trim	II
Double-ported globe valves with standard trim	II
Double-ported globe valves with special seats	III
Ball valves with metal seat	III
Cage-guided valves with special seats	IV
Unbalanced single-port globe valves	IV
Rotary-eccentric plug valves	IV
Unbalanced single-port globe with special lapping	V
All types of valves with resilient seats	VI

4.2. Valve Body

4.2.1. Globe

1. Single-ported, top-guided valves, as shown in Figure 1, are the simplest and least expensive of the globe valves. They are particularly useful where solids or abrasives must be handled because there are fewer cavities for solids to collect, and it is easier to replace the trim parts in these valves than in other types. The single-seating surface is convenient for machining to achieve tight shutoff.

2. The upstream pressure acts on one side of the single-ported valve plug, while the downstream pressure acts on the other. The actuator shall supply enough force to overcome this pressure imbalance. If the pressure drop or the plug area is large, the force required from the actuator may exceed practical limitations. Single-ported valves are usually limited to 100 mm (4 in) or smaller port sizes with low pressure drops. Valve size is even more limited with higher drops.

3. Double-ported valves, as shown in Figure 2, have two plugs arranged so that the pressure drop acts upward on one plug and downward on the other. Because of this counteraction, the actuator needs to develop only the thrust required to overcome friction and the imbalance caused by the stem area. Double-ported valves are difficult to manufacture in such a way that both plugs seat at exactly the same time; thus, they usually do not seal as tightly as single ported valves. In addition, their castings are more complex. These factors increase the cost of double-ported valves. Because of the limitations and added expense of double-ported valves, they are seldom used in new installations, except for the special applications mentioned below.

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4. Cage-guided valves allow balanced operation because a passage through the plug, shown in Figure 3, equalizes the pressure above and below the plug. The force resisting the pressure drop is supplied by the rigidity of the cage and plug and to a very small extent by the stem and actuator. The actuator force required is about the same as for double-ported valves. Cage-guided valves are best for most applications in which a balanced plug is required. Double-ported valves shall be considered where liquid shear is required for mixing or where abrasives that would cause excessive wear between the cage and plug are present.

5. Some valves are manufactured with quick-change trim where the seat is held in place by a cage assembly. This type of valve allows the trim to be changed more quickly than designs in which the seat is screwed into the body, but it is functionally a top-guided, single-ported valve and is unbalanced.

6. Globe valves with three process connections are available for combining, splitting, or directing flows. Some designs are similar to double-ported valves (Figure 9), except that skirt guiding is used because the lower port is where the lower guide would be. The guiding at the port reduces the bending movement of the stem. Other models use cage guiding (Figure 10). The pressure drop forces in the double-ported design are not balanced as they are in the single-outlet double-ported valve. The forces are balanced with the cage-guided design. Three-way globe valves are sometimes used for flow diversion, but plug or ball valves are better choices if tight shutoff is required.

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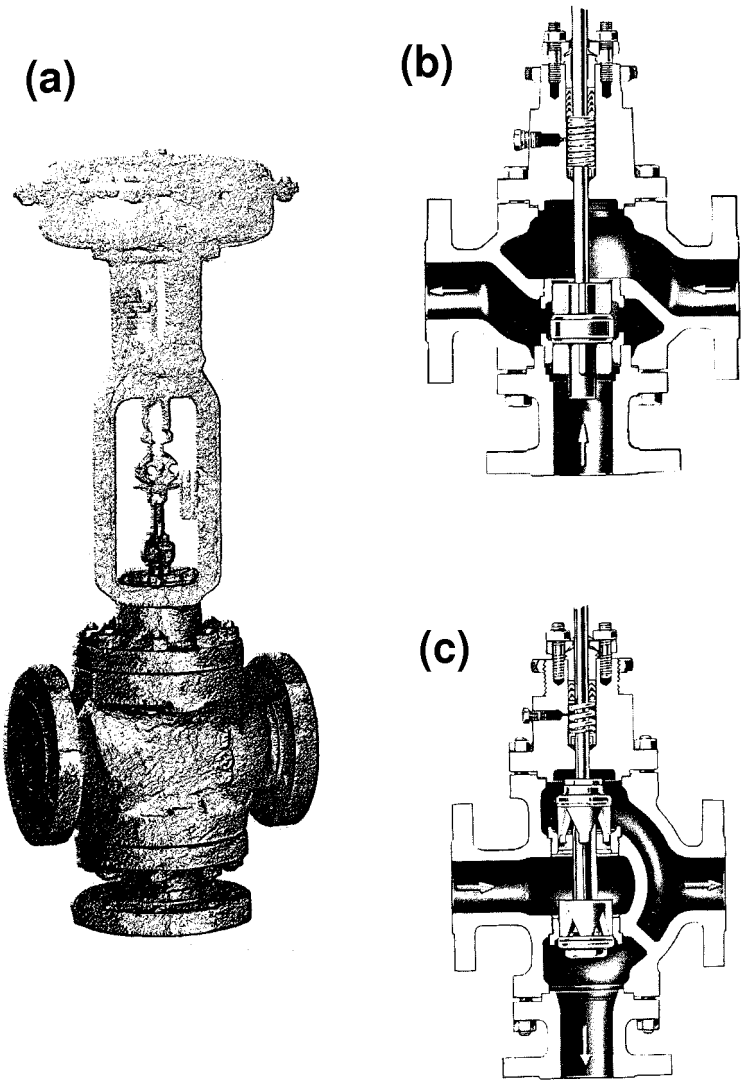
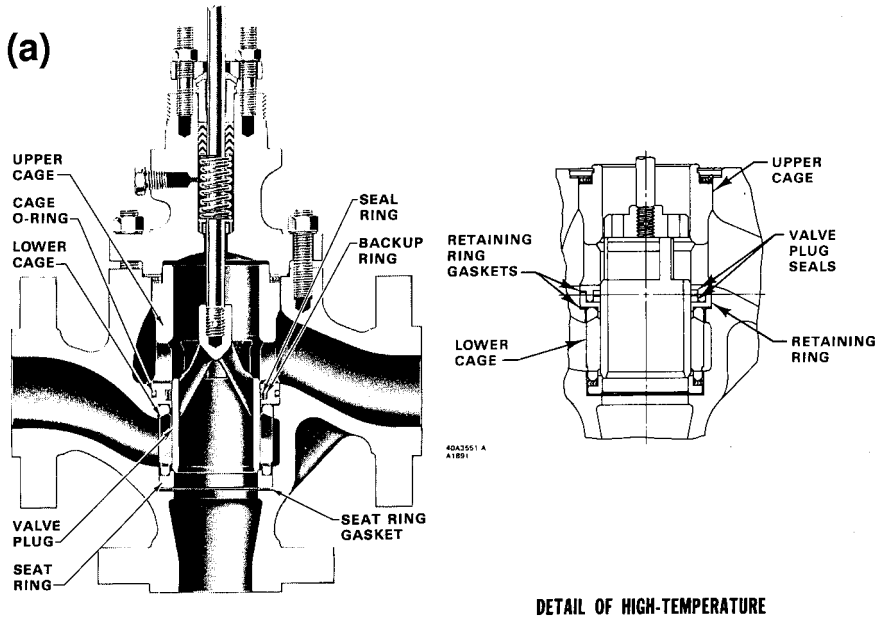
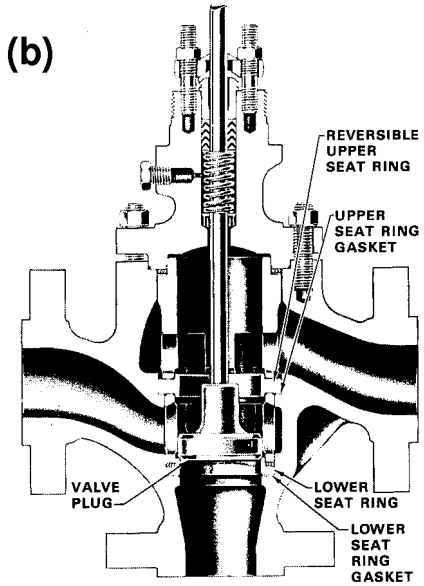


Figure 9: Three-Way Skirt-Guided Globe Valve: (a) External View Showing Position of Pneumatic Actuator; (b) Design with Quick Opening Valve Plug; (c) Design with V-Port Valve Plug (Courtesy of Fisher Controls)



STANDARD DESIGN YD

DETAIL OF HIGH-TEMPERATURE DESIGN YD TRIM



DESIGN YS

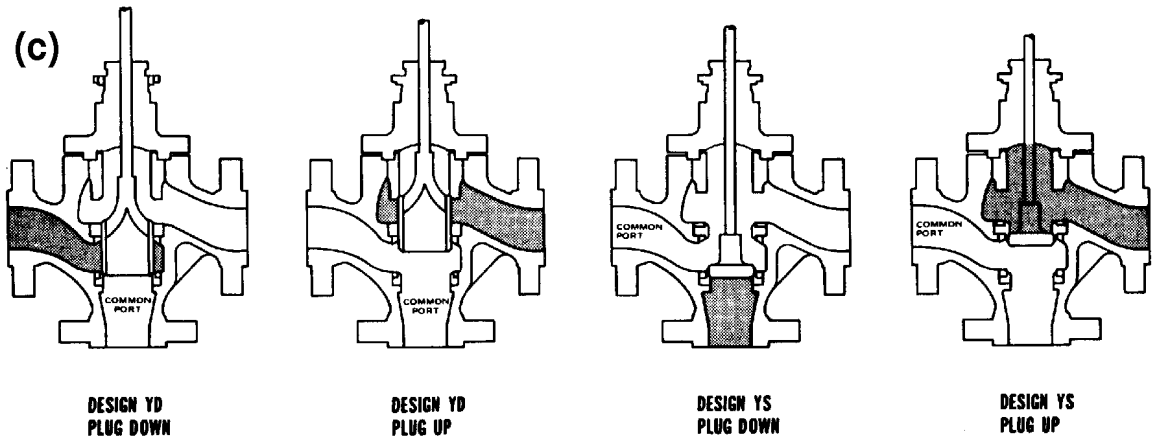


Figure 10: Cage-Guided Three-Way Globe Valve: (a) Standard Design; (b) Optional Design; (c) Cutaway Views of Both Designs Showing Flow Direction with Variations in Plug Position (Courtesy of Fisher Controls)

4.2.2. Angle Body

1. Angle valves are usually used for liquid dumps from separators with low flow rates, whereas the more rugged and expensive chokes are used to control two-phase flow from wellheads and in applications with large flow rates. Refer to the specialty valve section for other applications.

2. Angle valves are also useful for slurries, radioactive material, and other substances for which a self draining body is required.

4.2.3. Butterfly

1. Butterfly valves are not widely used in hydrocarbon service but are often used in fire water systems and utilities and as throttling valves on compressor suction lines. The characterized disks and geometries available from the various manufacturers make them worthy of consideration for many applications. They are particularly suitable for low pressure drops in large lines, but smaller sizes in some models can perform satisfactorily with drops well above 6900 kPa (1000 psi).

2. All-metal butterfly valves have a relatively high leakage rate, approximately 0.5 percent of the maximum flow. Other designs, using elastomer seals, are capable of very tight shutoff when new. Since the disk containing one of the sealing surfaces is always in the flow stream, butterfly valves have a greater tendency to leak with time than other designs. Only a few customized designs of butterfly valves are fire safe.

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4.2.4. Ball

1. Most ball valves have round ports through the ball. This design is well suited for on/off service, which is a ball valve's most common application in oil and gas production facilities. However, the design does not have good characteristics for control. Ports shaped to give better flow-throttling characteristics are available from some manufacturers. Larger flow rates are possible through customized ball valves than through equivalent sized globe valves.

2. Ball valves are either floating ball or trunnion-mounted. Floating ball valves have a slot in the ball which is perpendicular to the bore. The stem has flats machined onto it to fit into the slot. When the valve is closed, the line pressure forces the ball against the downstream seat to cause tight shutoff. Trunnion-mounted ball valves have a ball which is rigidly attached to the stem and a pin on the bottom of the ball that rides in a bearing. This ball does not move into the seat when closed. Floating ball valves are simpler to manufacture, and, thus, less expensive. They seal well on simple seats and are intrinsically fire-safe. They require more torque than trunnion-mounted balls and, thus, require a larger actuator for opening when full pressure differential is applied.

3. Trunnion-mounted balls require spring-loaded seals and are more expensive, but they can use smaller actuators. Some operating companies have rigid guidelines concerning floating ball versus trunnion-mounted ball valves. Selection is a tradeoff in which size, application, and pressure drop are considerations. By their design, ball valves are generally quarter turn lever-operated valves. Where high differential pressures may exist, gear operators may be needed for the torque required for opening or closing the valve.

4.2.5. Plug

1. Plug valves are quarter turn valves used for on/off service. A stem connected to a bored cylinder allows operation from open to close through a 90° rotation (see Figure 7). The cylinder, or plug, may be straight or tapered. Tapered plug valves often require lubrication after each use and are decreasingly in favor in modern designs. The valves may be manual or equipped with a quarter turn actuator.

2. Since the opening is smaller than the pipe inside diameter, plug valves cannot be used if pigging capabilities are desired. Plug valves are often less expensive than ball valves but have larger pressure drops associated with them.

4.2.6. Gate Valves

Gate valves are rising stem valves with a bored metal slab, or gate, attached to the stem (see Figure 11). The gate valve is the primary choice for most shutdown applications. Ball and plug valves are preferred for most manual on/off applications because they can be turned more quickly and provide a

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positive indication of on/off status by the position of their handle. Because of cost, gate valves are often used on large diameter, low pressure service.

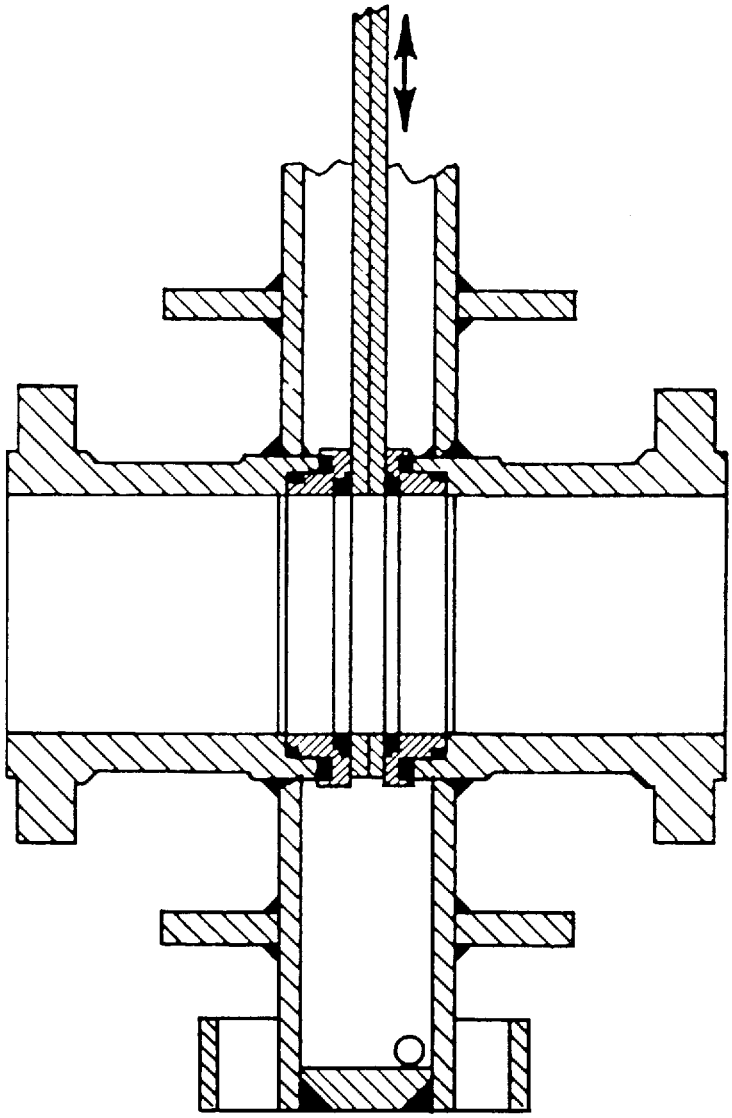

Figure 11: Typical Sliding Slab Gate Valve (Courtesy of Chilton Instrument Engineers' Handbook)

4.2.7. Specialty Valves

Typical specialty valves in use in the oil and gas industry are as follows:

1. The Masoneilan Camflex valve is a quarter-turn valve that functions like a characterized ball valve. It has the advantage of a cam action that applies greater sealing force when closed. The actuator has a cam which can characterize the flow as required.

2. The Saunders diaphragm valve, shown in Figure 12, has a weir and an elastomer boot. The valve is closed by the actuator pressing the boot to the weir. This type of valve is good for applications in which solids might wedge the valve open and prevent tight shutoff. This type of valve has temperature and pressure limitations related to the elastomer involved.

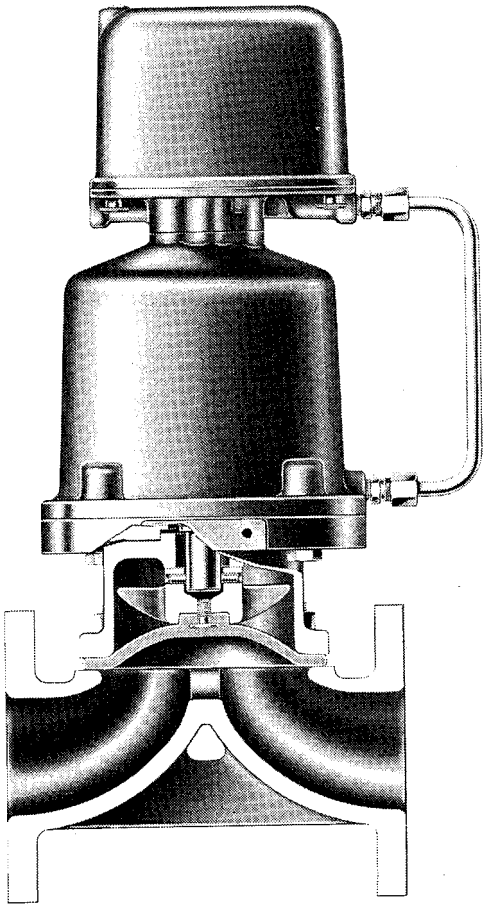

Figure 12: A Saunders Diaphragm Valve (Courtesy of Masoneilan Division, McGraw-Edison)

3. A pinch valve has an elastomer tube, or boot, which runs the length of the valve. The two pressure feet operate at the same time to pinch off the boot and stop the flow. This type of valve will not only shut off flow where solids may be lodged, but will keep the metal parts of the valve

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completely isolated from the process fluid. This type of valve has temperature and pressure limitations related to the elastomer involved.

4. The Grove Flexflo valve features an elastomer boot fitted around a slotted metal tube. The tube is divided in the center so that flow shall exit through the upstream slots and reenter the downstream slots. Air or gas pressure is applied to the outside of the boot, which acts against the process pressure inside the boot. When the pressure inside the boot is less than the pressure outside, the boot seals and flow is blocked. When the inside pressure exceeds that outside, the boot flexes and flow begins. This type of valve is excellent for back-pressure regulation of both gas and liquid. Its quick action makes it excellent for liquid surge relief. It is also effective as a relief valve on large pumps, such as fire water pumps, because it has two pressure reductions to reduce cavitation.

5. Tortuous path applications such as high letdown (pressure drop), high noise, cavitation, and corrosion/erosion require valves of special design. The angle body (choke) valve is the usual choice for high pressure drop applications. Noise reduction, cavitation, and corrosion/erosion control are usually obtained by selection of special valve trim systems. Refer to manufacturers for detailed information on specific valves.

4.3. Summary of Control Considerations

4.3.1.

Table 4 lists typical applications in which control valves are needed in production facilities and the most common choices of control valve body type for each one. The choice of a specific type in a specific application depends upon the properties of the fluid, pressure drop, availability of supply, and company preference.

Table 4: Control Valve Applications and Their Most Common Solutions

Wellhead	Choke valve
Line heater inlet	Choke valve with long nose
Separator oil outlet	Top-guided, single-port globe Angle-type globe valve
Separator gas outlet	Cage-guided globe valve Low-noise, cage-guided globe valve
Separator water outlet	Top-guided, single-port globe valve Angle-type globe valve Anticavitation globe valveChoke valve
Shutdown valves	Gate, Plug and Ball valve
Water systems	Butterfly valve
Compressor recycle	Low-noise, cage-guided globe valveCage-guided globe valve
Flow combining or splitting	3-way globe valveButterfly valve
Mixing	Double-ported globe valve

4.3.2.

Economy is an important consideration for most control valve users. In general, butterfly valves are the least expensive standard type of valve, followed by gate, plug, ball, and rotary plug, with globe valves being the most expensive. Valves that do not include flanges, such as wafer-type butterfly valves, between flange ball valves and screwed globe valves, are naturally less expensive than their counterparts with flanges. Valves with slip-on flanges are generally less expensive than valves with integral flanges, particularly when the body material is expensive.

4.3.3.

These guidelines usually apply, but exceptions are numerous. Control valve applications are very diverse, as are company guidelines. Also, the competitive nature of the control valve industry causes a continual shift in economic advantage. Frequent evaluation of the acceptable alternatives for an application is necessary to optimize economy in valve selection.

4.4. Materials Considerations

Control valves are available in a wide variety of materials to accommodate almost any fluid. Only a few of the available materials are commonly used in oil and gas production because the fluids are less corrosive and difficult to handle than in the chemical and other industries.

4.4.1. Sweet Natural Gas and Oil

1. Carbon steel castings are used for most control valves' bodies in sweet gas or oil service. ASTM A216 Grade WCB castings are standard for

most manufacturers and are satisfactory for process temperatures between -29°C (-20°F) and 538°C (1000°F). Some facilities have temperatures too low for WCB castings, in which case more expensive materials are selected. ASTM A352 Grade LCB castings can be used for temperatures as low as -46°C (-50°F). ASTM A352 Grade LC3 castings can be used as low as -101°C (-150°F). ASTM A351 Grade CF3, CF8, CF3M, and CF8M (cast alloy steels that have chemical compositions similar to type 304 or type 316 stainless steel) can be used down to -254°C (-425°F). The materials are listed in order of relative expense. Elevated temperatures reduce the pressure ratings for most metals. This derating is pronounced for carbon steels at temperatures above 400°C (750°F).

2. Chloride stress cracking of Austenitic stainless steels (300 series) can be a problem for temperatures above 60°C (140°F), and the problem increases in severity as the temperature increases. Stress cracking can occur when the chloride concentration is as low as 100 ppm, which is common in produced waters. Chloride stress cracking is generally not a problem with carbon steel or Martensitic stainless steels (400 series). The best material selection for this service is a carbon steel valve body with K-monel trim, but the cost is about 30 percent greater than for a standard valve. A carbon steel body with Martensitic stainless steel trim will give satisfactory service in most situations. Austenitic stainless steel valve bodies shall be avoided.

3. Cast iron in particular and ductile iron to a lesser extent are subject to fracture from mechanical impact or sudden temperature change. Of particular importance is the danger of a valve heated by a fire fracturing when fire water is applied. Cast iron and ductile iron are not normally used by Mobil.

4. Most manufacturers' standard trim for control valves is an assortment of stainless steels selected for strength, wear resistance, and machining qualities. These materials are all recommended for sweet gas and oil, and the manufacturers' standard trim is almost always sufficient.

4.4.2. Sour Natural Gas and Oil

1. The presence of hydrogen sulfide in hydrocarbons is cause for special care. The National Association of Corrosion Engineers publishes NACE Standard MR-01-75, which addresses this problem in detail, including the partial pressures involved and exact material requirements. In general, carbon and stainless steels can be used if they have been heat treated to control hardness. Cast iron cannot be used. The most common differences between standard valves and NACE specification valves are that the later feature heat treatment of the carbon steel body to a maximum hardness of HRC 22, replacement of Martensitic (400 series) stainless steel parts with Austenitic alloys (300 series), and special bolting.

2. Most valve manufacturers can supply a certificate with the valve to affirm that all materials used are suitable for sour service. Valves that

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fall within the NACE guidelines shall be purchased with an NACE certificate. Some companies elect to purchase NACE-certified valves for use with hydrogen sulfide services that do not fall within the NACE guidelines, even though this adds a significant cost, in case there is a future increase in H_2S content of produced fluids.

4.4.3. Carbon Dioxide

Carbon dioxide in the presence of water is very corrosive to carbon steel and cast iron. Type 304 and 316 stainless steel bodies are recommended for wet carbon dioxide. Dry carbon dioxide is not corrosive and special materials are not required. Where small amounts of carbon dioxide are present, most operators use carbon steel piping, valves, and equipment and protect against corrosion with an active chemical inhibition program.

4.4.4. Produced Water

1. Produced water usually contains dissolved salts and minerals, as well as traces of residual hydrocarbons, but very little oxygen. The lack of oxygen keeps corrosion problems to a minimum. Since residual hydrocarbons create some hazard, the same materials used for the associated hydrocarbon streams are used by some companies. Other companies feel that the small amount of hydrocarbons present in the water do not represent a hazard. Since cast iron has greater corrosion resistance to salt water and is less expensive than carbon steel, it is sometimes selected for produced water service. For more information, see the tutorial EPT 02-T-03 on Treating Oil from Produced Water.

2. The same precautions against chloride stress cracking which apply to heated crude oil also apply to heated produced water. Carbon steel valve bodies are preferable to stainless steel and K-monel trim is appropriate for difficult applications.

4.4.5. Seawater

Offshore facilities often use seawater for fire fighting, water injection, producing fresh water, and sanitation. Aerated seawater is corrosive to most iron-based material. Naval bronze is the best material for the service, but the cost is often prohibitive. A good compromise is epoxy-lined pipe and bronze trim. Cast iron valve bodies are not recommended for fire fighting service. Many systems have been installed using carbon steel valves with stainless trim, even though the need for periodic replacement because of corrosion is recognized. Fiberglass pipe and valves are becoming more common.

4.4.6. Sodium Hypochloride

Sodium hypochloride is used to inhibit growth of marine organisms in seawater systems. The concentration is usually low enough so that it does not create an excessive corrosion problem. The concentration is very high and very corrosive, however, in the piping and valves containing the sodium

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hypochloride prior to injecting it into the system. Polyvinyl chloride (PVC) piping and valves give satisfactory service in concentrations above 5 parts per million and below 38°C (100°F). Chlorinated polyvinyl chloride (CPVC) is suitable for temperatures up to 93°C (200°F). No special precautions are needed below 5 ppm.

4.4.7. Well Streams with Sand

Hardened trims are available for handling streams containing sand and other abrasives. Plugs and seats treated with tungsten carbide, chromium, or Stellite (Alloy 6 or Alloy 12) provide resistance to abrasion. The valve control type shall be selected to avoid moving surfaces between which sand can be trapped and cavities in which solids can collect. Single-ported, top-guided globe valves and angle globe valves are commonly used.

4.4.8. High Liquid Pressure Drop

1. Throttling control valves in liquid service are subject to erosion damage from the pressure drop. Valves in flashing or cavitating service are even more subject to damage. Stellite or chromium plug and seat coatings shall be considered for pressure drops above 1000 kPa (150 psi) in clean liquids or in flashing service. Tungsten carbide coating shall be considered for pressure drops above 2800 kPa (400 psi) or in cavitating service.

2. Often, a separate choke is used downstream of the liquid control valve in high pressure drop service. Between 50 percent and 75 percent of the pressure drop occurs across the choke, extending the life of the more expensive and more easily damaged control valve.

4.4.9. Packing

1. Every valve has a means of reducing the leakage around the sliding or rotary control stem to a minimum. To do this, a packing material is employed which keeps the fluid from escaping, yet allows the stem to move. The balance between sealing effectiveness and friction is adjusted either manually, by compressing the packing with bolts accessible at the top of the packing box, or automatically, by a compression spring and the process pressure.

2. Some types of packing require lubrication, and a port is provided to insert grease into the packing box. Usually, when there is a lubrication port, an isolating valve is also provided to allow insertion of grease without danger of fluid escaping through the lubrication port. The isolating valve has a chamber that allows a quantity of grease to be inserted with the valve closed. A bolt can then be started into the chamber, and then the isolating valve is opened. The bolt is then screwed all the way in to force the grease into the packing, and then the isolation valve is closed. A metal ring, called the lantern ring, is used in

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the center of the packing material to provide an area for the grease to enter the packing box.

3. Most manufacturers' standard packing is either Teflon or Teflon-impregnated fiber. This fiber has traditionally been asbestos, but similar materials that are less hazardous to handle are being substituted. Teflon packing is usually in the V-ring (chevron) form, and automatic compression is used, as shown in Figure 13. Teflon- impregnated asbestos requires lubrication and is usually supplied with manual compression, a lubrication port, and an isolating valve, as shown in Figures 14 and 15. These standard packings are suitable for almost all valves used in oil and gas production. The materials are resistant to all hydrocarbon materials and suitable for temperatures up to 232°C (450°F).

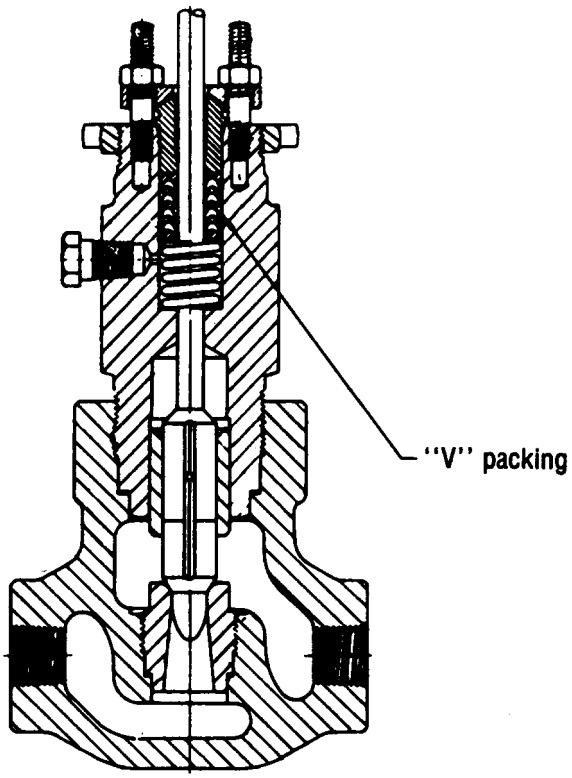

Figure 13: Automatic Compression Packing (Courtesy of Fisher Controls)

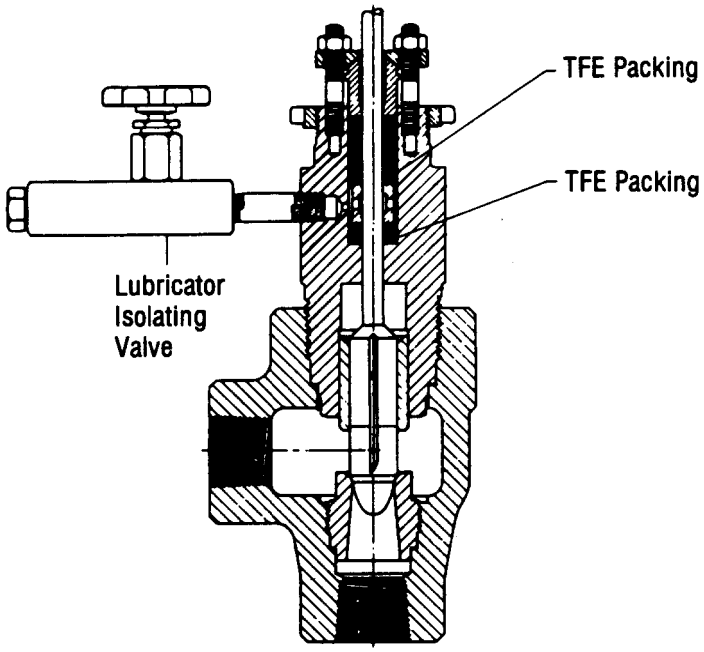

Figure 14: Manual Compression Packing (Courtesy of Fisher Controls)

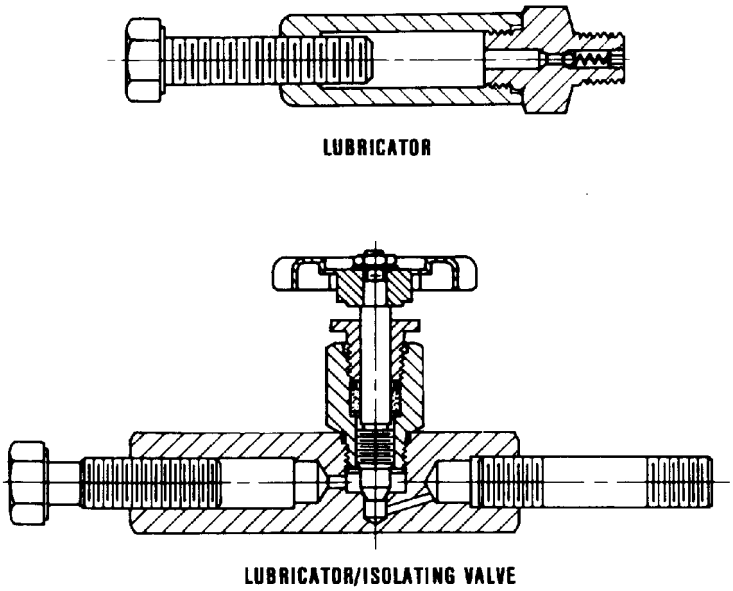

Figure 15: Packing Lubricator and Isolation Valve (Courtesy of Fisher Controls)

4. Graphite and semi-metallic packing are available for temperatures higher than 232°C (450°F). Bellows0-sealed stems are available for nuclear and

special chemical service. These special packings are rarely applied in production facilities.

5. Actuators

Every control valve shall have a device to position it as required. Most valves in a facility are positioned manually, but those referred to as control valves usually are positioned by some power-operated device. This device may be pneumatic, electric, hydraulic, or some combination of these.

5.1. Pneumatic Diaphragm

5.1.1.

Most globe-type control valves are controlled by pneumatic diaphragm actuators, which have flexible diaphragms installed between two pressure-containing casings. The diaphragm is connected to the stem of the actuator, which in turn is connected to the valve stem. A calibrated spring forces the stem to one extremity. Actuators in which the spring forces the valve open are called air-fail-open or air-to-close actuators. Actuators in which the spring forces the valve closed are called air-fail-closed or air-to-open actuators. Typical pneumatic diaphragm actuators are shown in Figure 16.

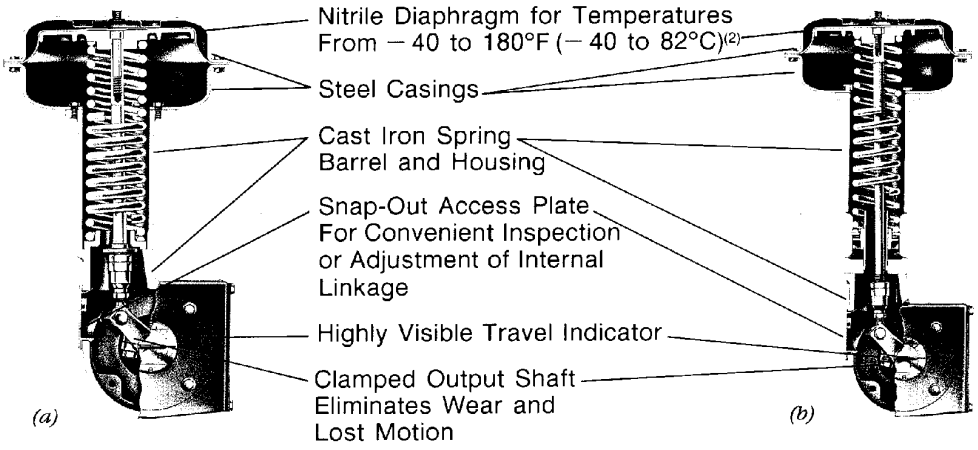
Nitrile Diaphragm for Temperatures From −40 to 180°F (−40 to 82°C)(2)
Steel Casings
Cast Iron Spring Barrel and Housing
Snap-Out Access Plate For Convenient Inspection or Adjustment of Internal Linkage
Highly Visible Travel Indicator
Clamped Output Shaft Eliminates Wear and Lost Motion
(a)
(b)

Figure 16A and B: Diaphragm Actuators: (a) Actuators for Rotary Stem Valve Showing Lever Arm Linkage; (b) Rotary Stem Valve Actuator with Adjustable Spring (Courtesy of Fisher Controls)

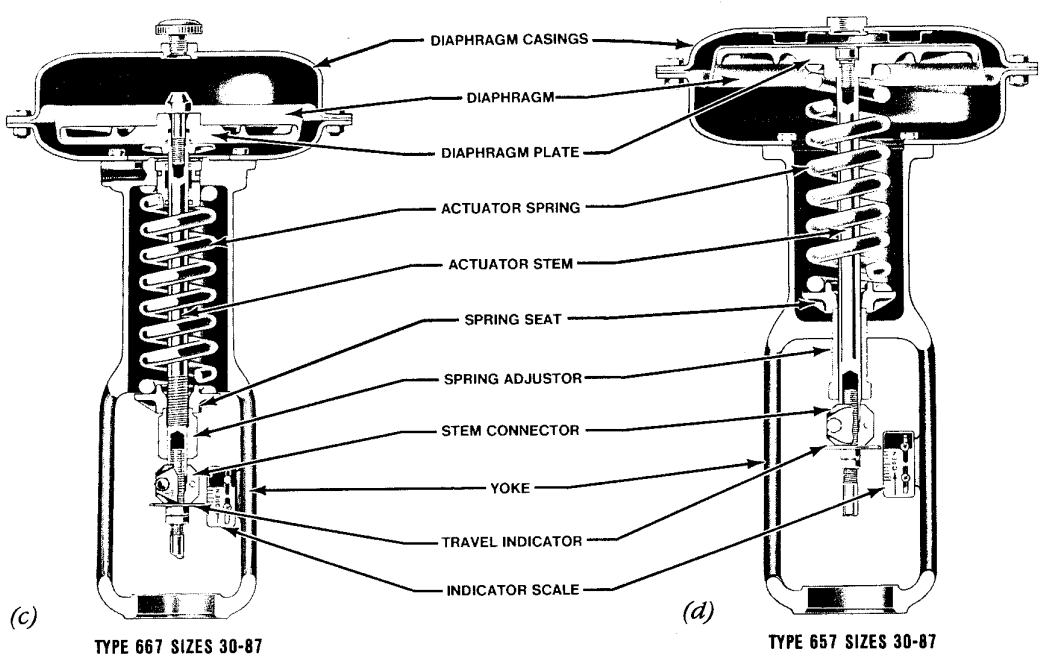

Figure 16C and D: Diaphragm Actuators: (c) Vertically Adjustable Valve Stem Actuator with Pneumatic Inlet Below Diaphragm; (d) Vertically Adjustable Valve Stem Actuator with Pneumatic Inlet Above Diaphragm (Courtesy of Fisher Controls)

5.1.2.

Most globe valves are closed by forcing the stem and, consequently, the plug, down into the seat. An actuator that is air-fail-open has a spring which forces the stem and diaphragm upward by the action of the top end of the spring against the diaphragm and of the bottom end against the case. Air is applied on top of the diaphragm to compress the spring and close the valve. Air-fail-closed valves have a spring which acts against the case at the top end and against the stem and diaphragm at the lower end. Air is applied below the diaphragm to compress the spring and force the stem upward.

5.1.3.

Pneumatic diaphragm actuators usually are operated by pressures between 20 and 100 kPa (3 and 15 psig) or between 40 and 200 kPa (6 and 30 psig). These pressure ranges are the same as the output of most pneumatic controllers and current-to- pneumatic transducers, which allows direct operation in many cases. The coil spring force is linear with respect to displacement, and the force applied by the diaphragm is a function of the effective diaphragm area and the amount of pressure applied. The result is that stem movement is directly proportional to the pressure applied, with only a small adjustment for friction necessary.

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5.1.4.

The pressure drop across a control valve causes a force to be applied to the stem. This is more prevalent with single-port, top-guided globe valves than with double- port or cage trim balanced valves, but it exists in any valve. When the pressure drop is large, this force is significant in relation to the spring pressure and keeps the stem from moving linearly with changes in control pressure. The effect of this force can be estimated and the actuator spring adjusted to compensate for the added force. This compensation is called "bench set"; it is done by adjusting the valve so that it travels from one extremity to the other with less than the full range of control pressure when process pressure is not present. When the process pressure is present, the valve can be expected to traverse with very nearly the entire control pressure range. For example, an unbalanced valve with a 25 mm (1 in) port size and 6900 kPa (1000 psi) of differential is expected to travel from closed at 41 kPa (6 psig) control pressure to open with 205 kPa (30 psig) control pressure and keep the valve closed for class IV shutoff with 0 psig on the diaphragm. The area of the plug can be calculated:

Metric :

$$A = 3.14 \times D^2 / 4 = 3.14 \times (25)^2 / 4 = 491\ mm^2$$

Customary :

$$A = 3.14 \times D^2 / 4 = 3.14 \times \frac{1}{4} = 0.785\ in^2$$

5.1.5.

The force required from the spring to overcome the differential pressure is:

Metric :

$$F = 491\ mm^2 \times 6900\ kPa / 10^3 = 3390\ Newtons$$

Customary :

$$F = 0.785\ in^2 \times 1000\ \ psi = 785\ lb$$

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5.1.6.

The force required for class IV shutoff for the example valve is given by the manufacturer as 7 N/mm (40 lb/in) of circumference:

Metric :

$$F = 7N / mm \times 25\ mm \times 3.14 = 549.5N$$

Customary :

$$F = 40\ lb / in \times 1\ in \times 3.14 = 125.6\ lb$$

5.1.7.

To these an allowance for friction shall be added; assume 220N (50 lb) for a total required force from the spring of:

Metric :

$$F = 3390 + 549.5 + 220 = 4159.5N$$

Customary :

$$F = 785 + 125.6 + 50 = 960.6\ lb$$

5.1.8.

The diaphragm effective area required to move the plug off the seat with 41 kPa (6 psig) and no differential pressure (bench set for 41 to 205 kPa, or 6 to 30 psig) is:

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Metric :

$$A = \left[\left(4159.5 + 220N\right) / 41kPa\right] \times 10^3 = 106{,}800\ mm^2$$

Customary :

$$A = \left(960.6 + 50\ lb\right) / 6\ \ psi = 168.4\ in^2$$

5.1.9.

Note that the friction force reverses direction when the valve starts to open, and thus shall be added again. With the 6900 kPa (1000 psi) differential pressure, the plug shall start to lift at:

Metric :

$$\left[\left(4159.5 - 3390 + 220\right)N / 106{,}800\ mm^2\right] \times 10^3 = 9.26\ kPa$$

Customary :

$$\left(960.6 - 785 + 50\right) lb / 168.4\ in^2 = 1.34\ \ psig$$

5.1.10.

The diaphragm can be sized so that the actuator is bench set at 69 kPa (10 psig). The diaphragm effective area required to move the plug off the seat with 69 kPa (10 psig) and no differential pressure (bench set for 69 to 205 kPa, or 10 to 30 psig) is:

Metric :

$$A = \left[\left(4159.5 + 220\right)N / 97\ kPa\right] \times 10^3 = 45{,}150\ mm^2$$

Customary :

$$A = \left(960.6 + 50\right) lb / 14\ \ psig = 72.2\ in^2$$

5.1.11.

With the 6900 kPa (1000 psi) differential pressure, linearity shall be improved, since a higher pressure is required to start to lift the plug. The plug shall start to lift at:

Metric :

$$\left[(4159.5 - 3390 + 220)N / 45{,}150\ mm^2\right] \times 10^3 = 21.9\ kPa$$

Customary :

$$(960.6 - 785 + 50)\ lb / 72.2\ in^2 = 3.1\ psig$$

5.1.12.

The purpose of this illustration is to show that bench setting an actuator to compensate for the differential pressure will allow use of a smaller actuator while improving linearity. These formulas apply only to this specific case and are not meant to be used in lieu of the manufacturer's recommended actuator sizing procedure. The many situations encountered and different types of valves and actuators available make presenting a set of general actuator sizing formulas impractical.

5.1.13.

Pneumatic diaphragm actuators operate directly on valve stems, which move vertically. They also can be attached by lever arms to operate rotary stem valves. They are simple to understand and maintain, as well as relatively inexpensive. They can also be operated directly by pneumatic controllers or current-to-pneumatic transducers. For these reasons, pneumatic actuators are used for control more often than any other type.

5.1.14.

Pneumatic diaphragm actuators are not without disadvantages. They are relatively low pressure devices. The diaphragm casings are limited to around 690 kPa (100 psig) working pressure, and actuator pressures over 205 to 275 kPa (30 to 40 psig) are seldom recommended. The available force is limited to the control pressure multiplied by the effective area; these actuators cannot develop the large amount of force required by some large valves with high pressure drops. Also, the travel of the stem is limited by the amount of flexibility in the diaphragm. The available travel ranges from less than 25 mm (1 in) for small sizes to about 75 mm (3 in) for large sizes.

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5.2. Piston Actuators

5.2.1.

A piston actuator is shown in Figure 17. The piston is driven up and down the cylinder by either pneumatic or hydraulic pressure to move the stem. The return force can be supplied either by a compressed spring or by pressure applied to the opposite side of the piston. The spring-return method is used with smaller actuators because of its inherent failure position and simpler control connections. The piston shall supply enough force to compress the spring as well as stroke the valve. Because of the added force needed to compress the spring and the difficulty of providing large enough springs, larger sized piston actuators are usually pressure-return types. Pressure-return piston actuators can be made fail-safe by adding a bottle to supply return pressure if the air supply fails.

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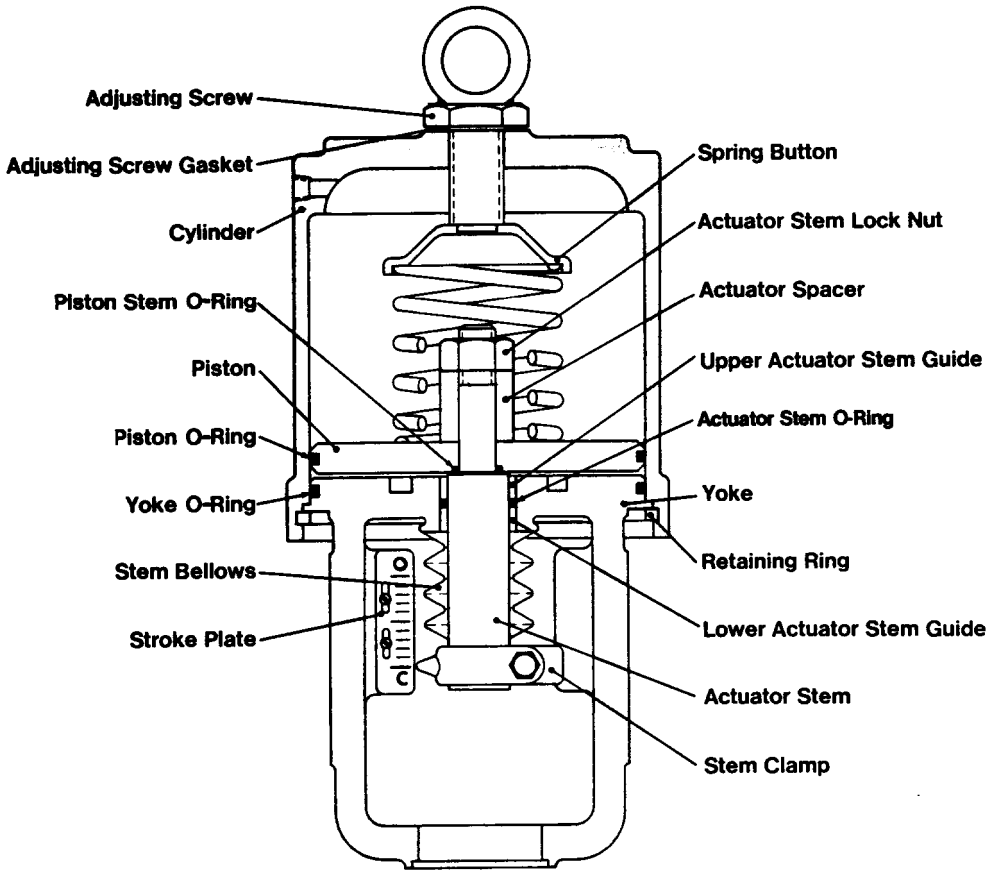

Figure 17: A Piston Actuator (Courtesy of Valtek, Inc.)

5.2.2.

A piston actuator can move a sliding stem valve directly, by attaching the valve stem to the actuator stem. Rotary stem valves can be actuated by translating the linear motion into rotary motion by a rack-and-pinion gear or yoke assembly. Pipe can be used for the cylinder, and the piston can be constructed so that it is rugged enough to allow use of much higher control pressures than with pneumatic diaphragm actuators. Control pressures up to 1030 kPa (150 psig) are commonly used with instrument air systems and up to 6900 kPa (1000 psig) with hydraulic systems. The amount of travel is limited only by the length of the cylinder and the stem.

5.2.3.

Although it is theoretically possible to construct a piston actuator that uses a calibrated spring for control, this is usually not done. Piston actuators are generally made for on/off service. They can be used for throttling by adding

a positioner. Positioners are used with pressure-return piston actuators to control modulating valves that are too large for pneumatic diaphragm actuators. A positioner allows a 20 to 100 kPa (3 to 15 psig), 40 to 200 kPa (6 to 30 psig), or 4 to 20 mA signal to modulate a valve actuated by a piston driven by a higher pressure.

5.3. Electric Actuators

Electric motors are sometimes used to actuate control valves when a reliable pneumatic source is not available. The most common type is a geared actuator for a rotary stem valve as shown in Figure 18. This type of actuator is well suited for on/off control, but is not very satisfactory for modulating control. Electric motors can be used to drive hydraulic pumps for actuation of piston-type actuators. Hydraulic actuators with self-contained, motor-driven hydraulic pumps and reservoirs are available, or a separate hydraulic supply package can be used for several valves.

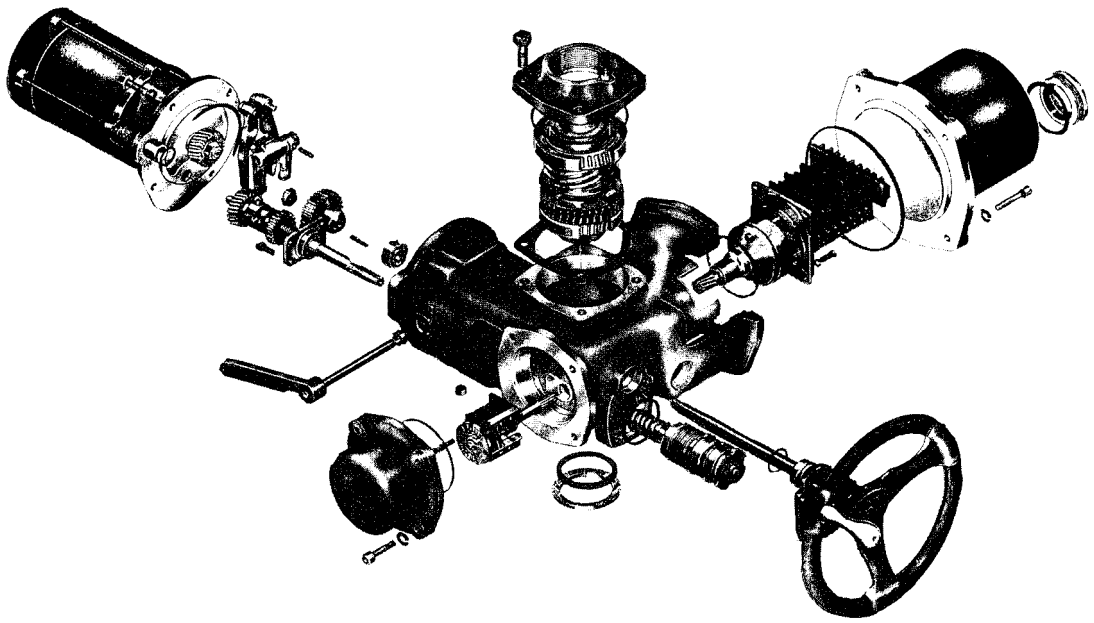

Figure 18: Geared Electric Actuator for a Rotary Stem Valve (Courtesy of Limitorque)

5.4. Positioners and Boosters

5.4.1.

A valve positioner is a device that mechanically monitors the valve position and supplies the correct pressure to drive the valve to coincide with the control signal (see Figure 19). Positioners can reduce the amount of flow

required from the controller or transducer, can drive actuators that require different pressure ranges than the available control signal, and can correct for the effects of process dynamics on the valve position. However, positioners shall not be used as signal multipliers.

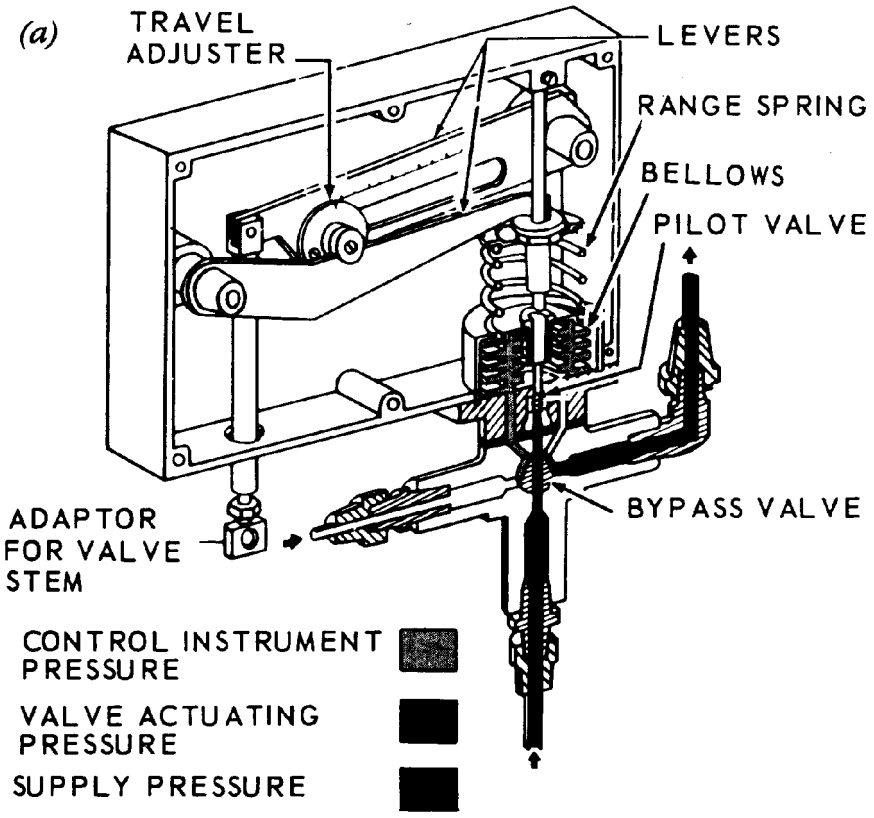

Figure 19A Valve Positioners: Schematic Showing Pressure Pathways (Courtesy of Moore Products Co., Spring House, PA)

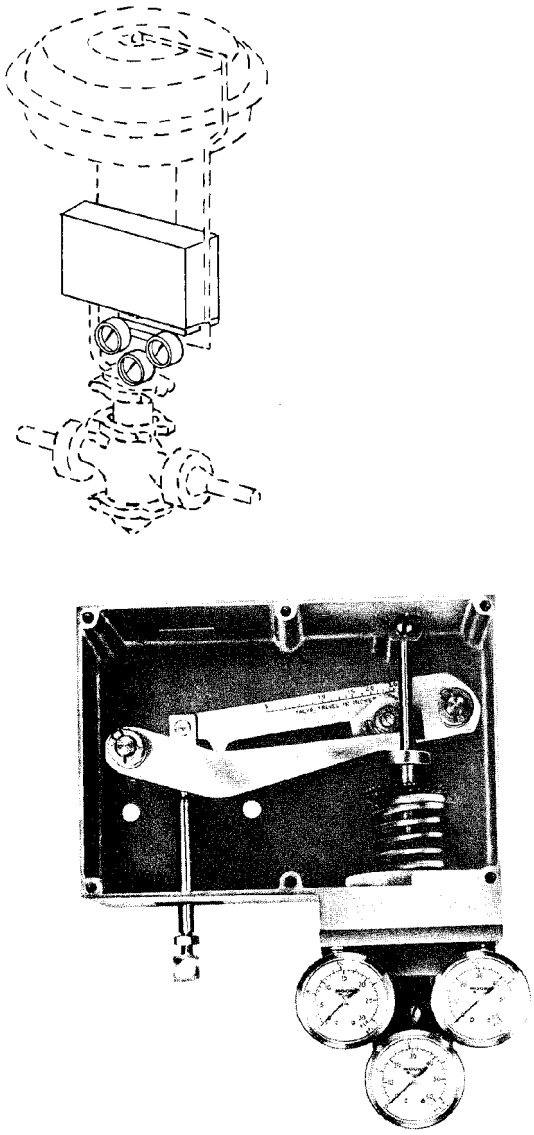

Figure 19B: Valve Positioners: Valve Positioner and Placement on Actuator (Courtesy of Moore Products Co., Spring House, PA)

5.4.2.

A valve booster limits the amount of flow required from the controller or transducer and can speed the valve action, but it cannot correct for process dynamics. The input and output pressures are usually the same. Figure 20 shows typical boosters.

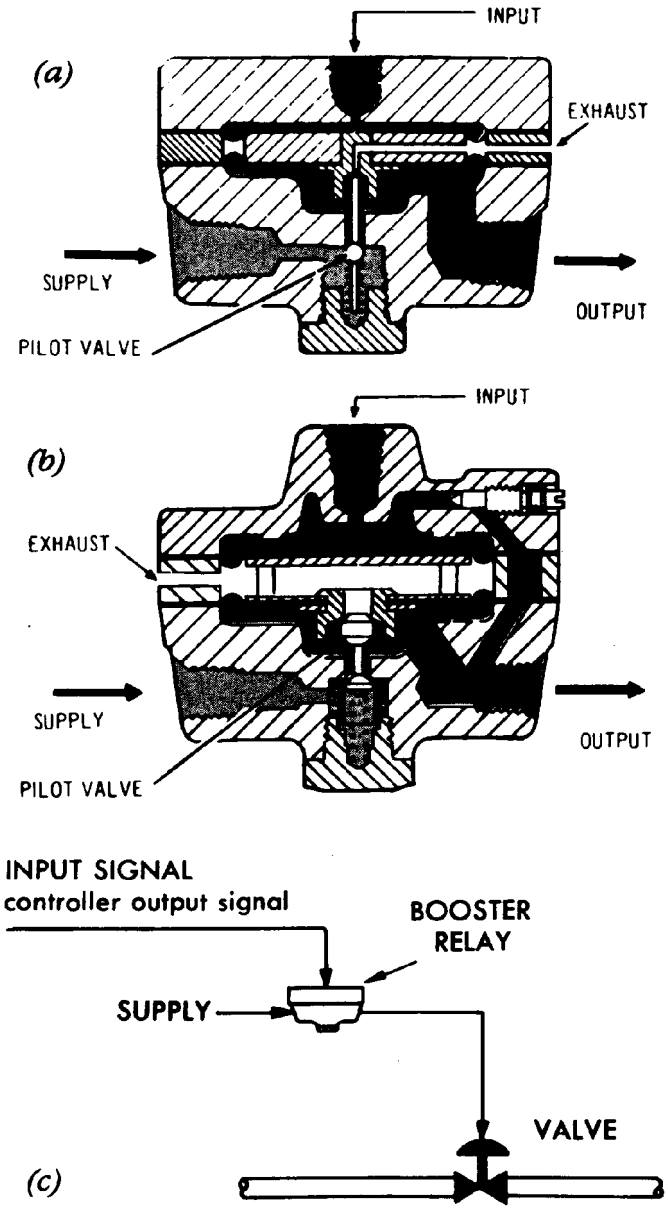

Figure 20: Valve Booster: (a) Schematic of High Accuracy, Low Capacity Booster; (b) High Capacity Booster; (c) Typical Circuit with Booster Valve Used to Improve Stroking Speed of Large Diaphragm Valve (Courtesy of Moore Products Co., Spring House, PA)

5.4.3.

Valve positioners shall be used when:

1. Piston actuators are used for control.
2. The actuator requires a pressure range different from the control range.
3. Multiple valves with different pressure ranges are controlled by a single controller (split range).

5.4.4.

Boosters shall be used when:

1. The control line is long enough to cause excessive delay in valve operation.
2. The controller or transducer does not provide enough volume to move the valve at the required speed.

5.5. Transducers

5.5.1.

Control valves are usually pneumatic devices, while controllers may be either pneumatic or electronic. When an electronic controller is to be used with a pneumatic control valve, a transducer is used to convert the electronic signal to a pneumatic signal. These transducers are commonly called I to P (or written I/P) from the common symbols for current and pressure. The most common signal levels are 4 to 20 mA input and 20 to 100 kPa (3 to 15 psig) output, but can be as required by the controller and the control valve.

5.5.2.

The I/P transducer can be combined with a positioner, usually an electronic positioner. Some engineers prefer to mount a transducer off the valve to isolate the electronics from the process vibration, considering the small economic penalty justifiable.

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6. Installation

6.1. Connections

6.1.1.

Control valves are most often installed between flanges. Butterfly valves and some ball and check valves are constructed so that they fit between two ordinary piping flanges. Some butterfly valves have lugs around the perimeter for the bolts to aid in installation. Globe valves and most actuated ball valves are not suitable for this type of attachment and are constructed with flanges, weld connections, or screwed connections for installation in the piping.

6.1.2.

Globe valves are available with both integral flanges and slip-on flanges. Integral flanges are more prevalent in production facilities. Slip-on flanges allow the flange to be made of carbon steel when the body is cast of a more expensive material suitable for the process fluid. They are more common in the chemical industry.

6.1.3.

Screwed connections are available for smaller-sized valves and are usually limited to 50 or 100 mm (2 or 3 in) bodies. Some operating companies allow screwed connections only in utilities; others limit the connection sizes to 38 mm (1.5 in) or below. Refer to the standards that apply to the project before ordering valves with screwed connections.

6.1.4.

Valves are available with socket-weld or butt-weld connections. Control valves are usually not welded into the line because they are high maintenance items that occasionally have to be replaced. In some very large applications welding may be necessary. Welded connections are also used to reduce leakages in services, such as hydrogen or high pressure steam, which are not common in production facilities.

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6.2. Bypass Valves

6.2.1.

Control valves are often installed with block and bypass valves. This allows the control valve to be isolated and removed for maintenance while the facility is in service. The bypass valve can be a manually operated valve similar to the control valve. The bypass can be manually positioned to continue operation while the control valve is out of service.

6.2.2.

If the bypass valve is a throttle valve (e.g., globe, butterfly), a second positive shut-off valve (e.g., ball, plug, gate) is sometimes installed in series to minimize the possibility of leakage during normal operation. Often, the bypass valve is a positive shut-off valve that is manually cycled when the control valve is being serviced.

6.2.3.

It is good practice to provide a drain or vent valve between the block valves so that the system can be drained or vented to atmospheric pressure prior to performing maintenance. Care shall be exercised in removing the actuator from the valve. Even though the valve may be isolated from the process by block valves and the segment of the line containing the vent valve depressurized, pressure could be trapped in the valve body. Manufacturers' recommendations shall be followed; one shall never stand directly over an actuator until the pressure seal between the valve and top works is broken.

6.2.4.

It is preferable to locate the bypass valve at a higher elevation than the control valve, although sometimes it is necessary to locate the bypass and control valves at the same elevation. When a bypass valve is installed at a lower elevation than the control valve, water and sediment shall collect in the bypass piping, accelerating corrosion, and it may become difficult to open the valve when needed.

6.3. Location

Every effort shall be made either to locate control valves at grade or to provide access platforms. Frequent maintenance is required, and servicing difficult to reach valves could be hazardous. The valve shall be installed so that the actuator is above the body of the valve (if possible) and so that there is sufficient clearance to lift the top works from the valve. Large valves may require crane or hoist access.

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7. Control Valve Sizing

7.1. General

7.1.1.

Control valve sizing is divided into three categories: incompressible fluids, compressible fluids, and two-phase flow. Incompressible liquids and compressible gases behave differently enough that separate sizing equations are required. Two- phase flow has unique characteristics that require special treatment; the flow coefficient is not simply the sum of those for the liquid and gas flows.

7.1.2.

The procedure usually used for valve sizing is to calculate the valve flow coefficient (C_v) needed for the process conditions and then to refer to the manufacturer's literature to find a valve of the type needed, sized so that the coefficients calculated are in the range of good control.

7.1.3.

The obvious objective of control valve sizing is to choose a valve that shall give good control over the required range. The usual procedure is to choose a valve with a maximum capacity of about double the normal flow rate. The minimum and maximum predicted flow rates shall also be considered. Satisfactory control can usually be obtained with the valve between 10 percent and 90 percent open, so the engineer has a good deal of latitude in his choice.

7.1.4.

Virtually all manufacturers have computerized valve sizing programs generally tailored to their line of valves. The ISA has accepted computerized sizing programs aimed at generic sizing, and most engineering contractors have their own software. Although each might approach the solution in a different manner, they all generally produce sizing within acceptable limits.

7.1.5.

The basic equations and procedures are provided in ISA Standards 534.1 and 534.3, the ISA Control Valve Selection and Sizing Handbook, and the Chilton Process Control Handbook. Refer to these documents for detailed calculation procedures and the following for basic concepts and considerations.

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7.2. Liquids

7.2.1.

Basic liquid sizing procedures are based on turbulent flow. Non-turbulent flow is rarely encountered in production facilities because very low velocities and very viscous liquids are necessary to produce it.

7.2.2.

The minimum pressure in the stream is reached somewhere inside the control valve at a point called the vena contracta. The pressure downstream of the vena contracta increases somewhat, but not back to the inlet pressure. If the pressure at the vena contracta is below the vapor pressure of the liquid, some or all of the liquid will vaporize and produce a condition called choked flow. When choked flow is reached, reductions in downstream pressure have little, if any, effect on the flow rate. Choked flow shall be checked in almost every liquid valve calculation. The pressure at the vena contracta can reach surprisingly low values and may even approach a perfect vacuum.

7.2.3.

The required C_v shall be calculated for both choked flow and non-vaporizing flow, and the larger valve shall be used. If the C_v required by the choked formula is larger than that required by the regular formula, choked flow exists; otherwise it does not. Choked flow will be caused by either flashing or cavitation.

7.2.4.

Flashing occurs when the liquid vaporizes in the vena contracta and the pressure downstream is lower than the vapor pressure. This form of choked flow requires an increase in C_v for a given flow rate. It does not cause other severe problems, provided the downstream piping and process components are designed to accommodate the two-phase stream that results.

7.2.5.

Cavitation occurs when the liquid vaporizes in the vena contracta and the pressure downstream is higher than the vapor pressure. The gas produced in the vena contracta implodes in the valve outlet or the downstream piping. The implosion of bubbles against metal surfaces can cause severe erosion and shall either be avoided or sacrificial members used. Cavitation causes a sharp clicking noise, which can sound as if gravel is in the stream.

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7.2.6.

Predicting choked flow with either flashing or cavitation is a straightforward calculation when single-component streams are involved.

7.2.7.

In most production vessels in a facility the liquid is in near equilibrium with a gas phase. That is, the liquid is at its vapor pressure. As the liquid flows through the control valve, gas shall be "flashed", or liberated, from the liquid. Some of this gas may be condensed back into liquid as the pressure recovers from the vena contracta to the pressure in the downstream piping. As long as there is a pressure drop across the valve, some gas will "flash". Thus, choked flow conditions shall be considered for most liquid control valves.

7.3. Gas

Sizing valves for compressible fluids is somewhat more involved than sizing valves for liquids. The expansion of the fluids between the inlet and the outlet of the valve shall be accounted for, and thus several new factors enter into the equation. The choked flow condition for compressible fluids occurs when the jet stream at the vena contracta attains sonic velocity. This adds new calculations. Also, aerodynamic noise often presents selection problems, and calculation of noise generated by valves in compressible service is required.

7.4. Two-Phase Flow

When a mixture of liquid and gas is flowing through a valve, the required C_v is more than the sum of that required for the liquid and that required for the gas. The required C_v rises almost linearly from the sum when the gas content by volume is 0 percent to double the sum when the gas content is 90 percent of the stream. The required C_v then falls rapidly back to the sum when the gas content is 100 percent. Normal practice is to add the respective areas for liquid and gas and use that combined area to determine required C_v for mixture.

7.5. Noise

7.5.1.

Control valve noise falls into three basic categories: mechanical noise, hydrodynamic noise, and aerodynamic noise.

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7.5.2.

Mechanical noise is caused by parts of the valve contacting each other. This makes a rattling sound, usually at fairly low frequencies. In modern valves in good condition, mechanical noise is not a problem. It is possible that a valve with worn stem guides or broken parts can become noisy, in which case the defective parts shall be replaced.

7.5.3.

Hydrodynamic noise is primarily the result of cavitation. Physical damage to the valve from cavitation occurs before the sound level is a problem; therefore, the measures to prevent cavitation discussed in the Liquid Control Valve Sizing section will also prevent excessive noise.

7.5.4.

Aerodynamic noise is a frequently encountered problem in production facilities. Sound level increases rapidly when choked flow is reached in the vena contracta and even more rapidly when the velocity in the valve outlet reaches 0.3 to 0.5 Mach. The sound level is difficult to estimate by inspection; therefore, a sound level calculation is advisable for every control valve in compressible fluid service.

7.5.5.

The human ear does not respond to all frequencies of sound equally. A curve has been developed to weight sound frequencies in accordance with how the human ear responds. This is known as the A-weighing curve, and sound levels weighted for this curve are abbreviated as dBA. Control valve noise is generally calculated in dBA. No method of predicting the frequency distribution of the noise or the sound level at any particular frequency is in general use at this time.

7.5.6.

Permissible sound pressure levels for occupied areas as defined by the U.S. Occupational Safety Health Act of 1970 range from 90 dBA for 8 hours exposure per day to 115 dBA for 15 minutes or less per day. Sound levels above 110 dBA can cause mechanical damage to the valve. Instances in which a person would spend eight hours a day within three feet of a valve would certainly be rare, but there are many noise sources in a facility, and aggregate noise would be difficult, if not impossible, to predict. From these data, the industry consensus and many company standards have established 90 dBA at three feet (nominally one meter) distance from the valve as an acceptable noise level.

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7.5.7.

The ISA has yet to establish an accepted method for calculating noise. To establish a method that is valid for the many different designs of valves currently manufactured would be difficult, particularly for the low noise designs. At the present time, each manufacturer has noise prediction methods developed for his particular designs. The methods yield fairly consistent results for comparable valves in the region of 80 to 120 dBA, which is the area of primary interest. The results diverge quite a lot beyond this region because they are mathematically very different. Preliminary noise calculations with a selected manufacturer's method are useful, but a final check shall be made after the manufacturer and model are selected. Most manufacturers shall provide such a calculation with the quotation.

7.5.8.

When the calculation shows the sound level to be unacceptable, either the sound generated shall be reduced or resistance added to the path the sound must travel. The preferred method is to reduce the sound produced, because path treatment shall not reduce the added wear associated with the high sound level, and path treatment usually causes a higher noise level in some other location. It is usually more practical to select a valve that produces less noise than to change the process conditions. Standard globe valves are slightly less noisy than equivalent ball or butterfly valves, but if a large noise reduction is needed, a valve designed for reduced noise is indicated. Anti-noise valve designs are shown in Figures 21.

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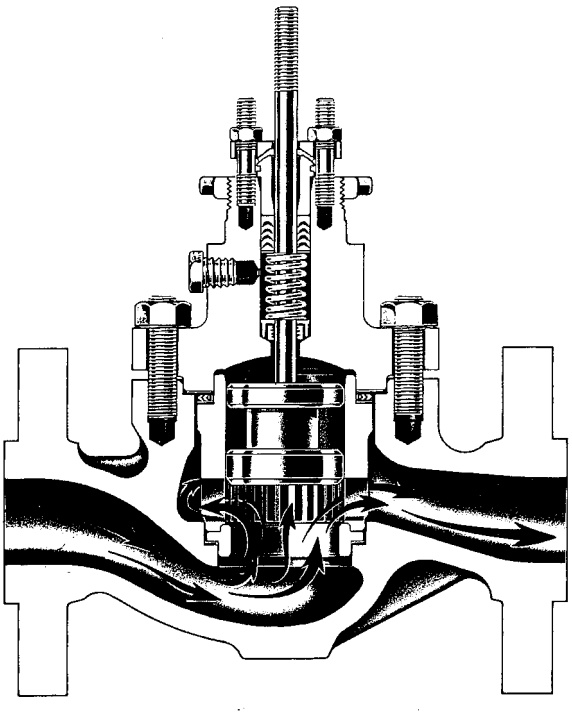

Figure 21A Antinoise Valves: Typical Cage-Type Valve (Courtesy of Fisher Controls)

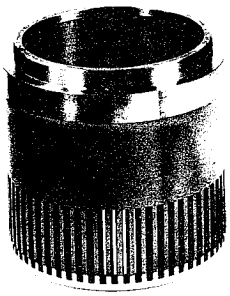

Figure 21B: Antinoise Valves: Whisper Trim I Trim (Courtesy of Fisher Controls)

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Figure 21C: Antinoise Valves: Alternative Whisper Trim III Trim (Courtesy of Fisher Controls)

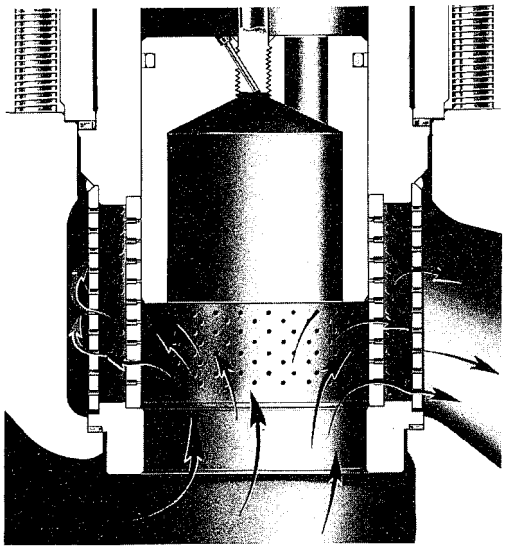

Figure 21D: Antinoise Valves: Flow Path for Cage (Courtesy of Fisher Controls

7.5.9.

Most manufacturers offer special valves that produce less noise than their standard designs. Two principles are commonly used: dividing the stream into several vena contractas, and dividing the pressure drop. Most low-noise valves are cage-guided globe valves with specially designed cages. The most commonly used method is to drill holes in the cage small enough and far enough apart to produce separate jets. There are valves with two cages, for dividing the pressure drop as well. The disadvantages to these valves are that

(a) the small holes are subject to clogging and (b) a larger valve is required for a given flow, making them more expensive than regular valves.

7.5.10.

Another way to reduce noise is to add mass to the system. The usual way of doing this is to increase the size or schedule of the downstream piping. Each of the noise calculations has a factor to account for the downstream piping mass, so the effect of increasing the piping mass can readily be determined.

7.5.11.

Placing a restriction downstream of the control valve to divide the pressure drop will also reduce the noise produced. The most effective restriction is a plate or cone, usually called a diffuser, that is drilled with a number of small holes. A typical diffuser is shown in Figure 22. The use of multiple holes rather than a single orifice helps to minimize the noise. Calculations used to assess the pressure drop division and the noise created by the combination of a valve and diffuser are not covered in this document. The combination is employed when use of a low noise valve and increase in pipe size and schedule are not adequate. A control valve specialist or the manufacturer shall be consulted if a diffuser seems to be required.

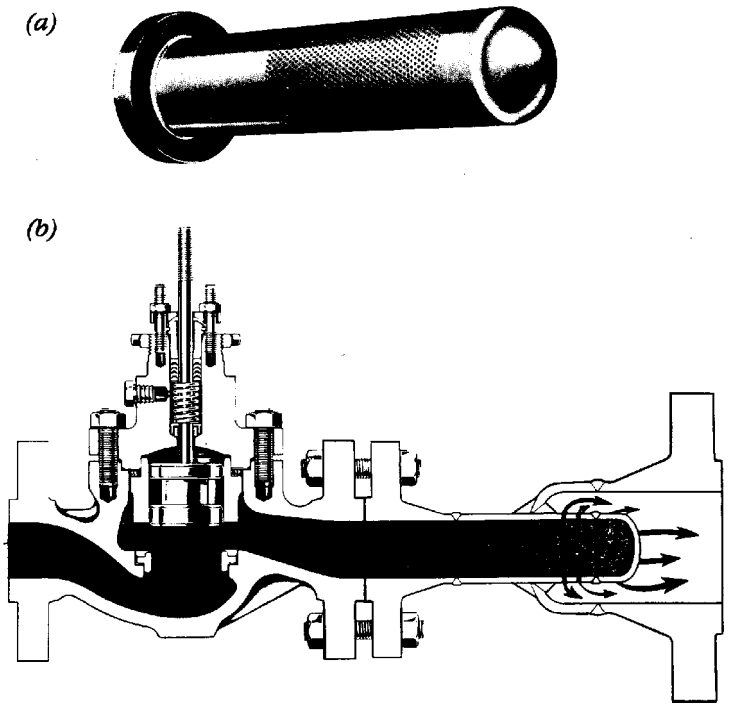

Figure 22: Diffuser: (a) In-Line Diffuser; (b) Control Valve with In-Line Diffuser (Courtesy of Fisher Controls)

7.5.12.

Path treatment, or keeping the noise from reaching the hearer, can be useful in some circumstances. Because path treatment does not reduce the damage to the valve, the sound level shall be reduced by source treatment to below 110 dBA before path treatment is considered.

7.5.13.

The most common path treatment is acoustic insulation of the pipe. This can reduce the noise by 20 dBA or more, but the noise is propagated downstream and will reappear where the insulation stops. Because of this, the insulation shall be carried to the next vessel, piece of equipment, or facility boundary, or to an area where the noise will not be a problem. Barriers such as concrete block walls can be erected between the valve and occupied areas, but the noise on the valve side of the wall will be intensified.

7.5.14.

Silencers, which are similar to automobile mufflers, can be installed in the line to reduce noise propagated downstream. These are fairly expensive and shall be considered only in difficult situations and used within the manufacturer's recommendations.

7.5.15.

Sound propagates downstream with little attenuation. It propagates upstream also, but if the vena contracta is sonic it will block further propagation. If the vena contracta is subsonic, a globe valve will cause about 10 dBA of reduction. If path treatment is used, it may be required upstream of the valve as well as downstream if critical flow is not present and the calculated noise is more than 10 dBA above the acceptable level.

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Control Valves and Actuators

MP 32-P-04

July 1998

Scope

This Mobil Engineering Practice (MEP) presents recommendations for the installation and application of control valves and related accessories. It supplements and is to be used in conjunction with API STD 553 and MP 32-P-01.

Version 0

Table of Contents

Scope **1**

1. References **4**

1.1. MEPS–Mobil Engineering Practices 4

1.2. Mobil Data Sheets 4

1.3. API–American Petroleum Institute 5

1.4. ASME–American Society of Mechanical Engineers 5

1.5. ASTM–American Society for Testing and Materials 5

1.6. CFR–U.S. Code of Federal Regulations 6

1.7. FCI–Fluid Controls Institute 6

1.8. ISA–International Society for Measurement and Control 6

1.9. NAS–National Aerospace Standards 6

1.10. NEMA–National Electrical Manufacturers Association 6

2. General **6**

3. Control Valve Selection **7**

3.1. Saunders Valves 7

3.2. Choke Valves 7

3.3. Flow Limiting and Pressure Letdown 7

4. Self-Actuated Regulators **8**

5. Control Valve Sizing **8**

5.1. Valve Pressure Drop 8

5.2. Two-Phase Flow 9

6. Control Valve Sound Levels **9**

7. Control Valve Actuators **10**

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7.1. Subsea Applications 10

8. Control Valve Accessories 12

9. Marking and Coatings 13

10. Documentation and Data Sheets 14

11. Inspection 14

11.1. Inspector/Agent 14

12. Testing 14

13. Modifications to API STD 553 15

Appendix: Inspection Checklist for Control Valves 29

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1. References

The following publications form a part of this Practice. Unless otherwise specified herein, use the latest edition.

1.1. MEPS–Mobil Engineering Practices

MP 00-P-05	Noise Control
MP 03-P-02	Pressure Casting Inspection
MP 16-P-01	Piping-General Design
MP 16-P-31A	Piping-Classifications-(E&P, On/Offshore)
MP 32-P-01	General Requirements for Instrumentation
MP 32-P-08	Control Centers
MP 32-P-19	Instrumentation Piping and Tubing Fittings
MP 35-P-01	Painting - General Requirements
MP 57-P-02	Pressure Containing Equipment - Welding & Inspection

1.2. Mobil Data Sheets

Mobil Data Sheets	Mobil Data Sheet Home Page
T3204C01	Control Valves & Actuators - Self-Actuated Temperature Regulators - Customary Units
T3204M01	Control Valves & Actuators - Self-Actuated Temperature Regulators - Metric Units
T3204C02	Control Valves & Actuators - Control Valves - Customary Units
T3204M02	Control Valves & Actuators - Control Valves - Metric Units
T3204C03	Control Valves & Actuators - Pressure Control Valves Pilots & Regulators - Customary Units
T3204M03	Control Valves & Actuators - Pressure Control Valves Pilots & Regulators - Metric Units
D3204C01	Control Valves & Actuators - Documentation Requirements Sheet
I3204C01	Control Valves & Actuators - Inspection & Testing Requirements Sheet
T3208C01	Control Centers - Customary Units
T3208M01	Control Centers - Metric Units

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T3208C02	Control Centers - Pressure Control Valves & Regulators - Customary Units
T3208M02	Control Centers - Pressure Control Valves & Regulators - Metric Units
T3208C03	Control Centers - Self-Actuated Temperature Regulator - Customary Units
T3208M03	Control Centers - Self-Actuated Temperature Regulator - Metric Units
D3208C01	Control Centers - Documentation Requirements Sheet
I3208C01	Control Centers - Inspection & Testing Requirements Sheet

1.3. API–American Petroleum Institute

API RP 17A	Recommended Practice for Design and Operation of Subsea Production Systems Second Edition
API STD 553	Refinery Control Valves
API STD 609	Lug- and Wafer-Type Butterfly Valves

1.4. ASME–American Society of Mechanical Engineers

ASME B16.5	Pipe Flanges and Flanged Fittings NPS 1/2 Through NPS 24
ASME B1.20.1	Pipe Threads, General Purpose (Inch) Revision and Redesignation of ASME/ANSI B2.1-1968 R(1992)

1.5. ASTM–American Society for Testing and Materials

ASTM A193/A193M REV B	Standard Specification for Alloy-Steel and Stainless Steel Bolting Materials for High-Temperature Service
ASTM A213/A213M REV A	Standard Specification for Seamless Ferritic and Austenitic Alloy-Steel Boiler, Superheater, and Heat-Exchanger Tubes
ASTM A269	Standard Specification for Seamless and Welded Austenitic Stainless Steel Tubing for General Service
ASTM A320/A320M REV A	Standard Specification for Alloy Steel Bolting Materials for Low-Temperature Service E1-1995 R(1995)

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1.6. CFR–U.S. Code of Federal Regulations

40 CFR 61 Subpart V	Environmental Protection Agency - National Emission Standard for Equipment Leaks (Fugitive Emission Sources)

1.7. FCI–Fluid Controls Institute

FCI 70-2	Quality Control Standard for Control Valve Seat Leakage

1.8. ISA–International Society for Measurement and Control

ISA 0-87664-234-2	Handbook of Control Valves – 2nd Edition
ISA S75.01	Flow Equations for Sizing Control Valves R(1995)
ISA S75.19	Hydrostatic Testing of Control Valves

1.9. NAS–National Aerospace Standards

NAS 1638	Cleanliness Requirements of Parts Used in Hydraulic System

1.10. NEMA–National Electrical Manufacturers Association

NEMA MG 1	Motors and Generators Revision No. 1 - December 1993; Revision No. 2 - April 1995

2. General

The installation and application of control valves and related accessories shall be in accordance with requirements of this MEP, unless superceded by more stringent local regulations. API STD 553 also includes requirements for hydraulically-operated and motor-operated valves.

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3. Control Valve Selection

3.1. Saunders Valves

Saunders and chemical service pinch valves may be used in applications involving slurries and corrosive chemicals.

3.2. Choke Valves

Choke valves are used in high-pressure arduous service (e.g., wellhead flow control). Several designs or internals are used by various manufacturers.

Multiple orifice choke valves are manufactured to operate reliably and withstand temperatures ranging from 10–120°C (50–250°F) and pressures up to 69,000 kPa (10,000 psi). They are used in a variety of environments, including CO_2 injection, H_2S service, cold temperatures and subsea service. Multiple orifice choke valves are designed and manufactured to meet API, ANSI, ISA and NACE specifications.

Most choke valves require careful consideration of construction materials because of exposure to entrained solids, high velocities, temperatures and pressures. Impingement of particles onto valve body walls can be detrimental. Various hard inserts can be used to direct the flow away from the valve body walls.

3.3. Flow Limiting and Pressure Letdown

Flow limiting using mechanical or pneumatic means to limit valve stroke shall not be permitted on control valves. Where excessive flow could be hazardous, circuit elements other than control valves, such as restriction orifices, fixed chokes, car-seal characterized block valves or adjustable chokes, shall be used to limit flow. The specific method for each given application requires approval.

- A multistage cascade letdown valve may be used for high-pressure letdown service in the range of 2750–41,500 kPa (400–6000 psi) on clean fluids. To prevent body erosion and lengthen the path in the recovery cone, a high-pressure letdown valve may have an oversized body and reduced-size inner port.
- For ultra high-pressure, special application letdown service (in the range of 41,500–310,000 kPa [6000–45,000 psi] to atmospheric pressure), a high response, high-pressure, commercially available valve shall be considered. Custom designed valves also may be used. In addition to the sizing calculations, detailed design data and stress and "hoop" calculations are required of the valve manufacturer and approval shall be obtained.

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- For high-pressure letdown service on both clean liquids and very fine solids bearing fluids, the tortuous path, velocity controlled type of valve is an acceptable design; however, letdown shall not be exclusively limited to such design.
- The "multiple orifice" feature refers to the use of two adjacent discs, each of which contains a pair of circular openings.
  - The two discs are diamond-lapped on the mating surfaces. Standard discs are made of ceramic; tungsten carbide discs are offered for extreme erosive, corrosive services and very high-pressure drops.
  - As one disc is rotated with respect to the other, the flow area is enlarged or reduced proportionally, thus creating a change in the volume of liquid and/or gas passing through the valve.

4. Self-Actuated Regulators

- Self-actuated pressure regulators may be used for services where a variation of 10 percent of the set pressure is not objectionable (i.e., fuel gas, tank N_2 blanketing, etc.).
- Use of self-actuated pressure regulators for upstream pressure greater than 687 kPa (100 psi) requires approval.
- Pilot-operated regulators, rather than self-actuated pressure regulators, shall be used where accurate control is required. Yoke mounted pilots require approval.
- Actuator and/or pilot shall withstand maximum upstream pressure of regulator unless other means of pressure relief is provided.
- The controlled output signal shall be indicated on the pilot.
- Cage-guided trim shall not be used in slurries or in gas services containing particulates. (e.g., fuel gas).

5. Control Valve Sizing

5.1. Valve Pressure Drop

Control valve pressure drop shall be $33^1/_3$ percent of all other friction losses in the system, at the maximum process flow rate or 100 kPa (15 psi), whichever is greater.

The pressure drop allocated to a control valve in the suction or discharge line of a centrifugal compressor shall be 5 percent of the suction absolute pressure or 50 percent of the system dynamic losses (exclusive of the control valve) at the compressor rated point, whichever is larger. Detailed analysis of the valve performance stability, when installed

under any of the above pressure drop conditions, shall be required before approval is issued. Instability could result from varying flows, unstable pneumatic supply, control pressure fluctuations, controller remote set point fluctuations, etc.

For fluids flowing from one piece of equipment to another at lower pressure, the pressure drop allotted to the control valve shall be as specified above or 10 percent of the lower terminal pressure, whichever is greater.

Approval is required for use of control valves with available pressure drop which does not meet the above criteria or if the pressure drop is less than 10 percent of the upstream absolute pressure.

5.2. Two-Phase Flow

Control valve size in gas/liquid two-phase flow shall be determined by the equivalent area method: that is, calculate C_v for gas and liquid flow separately. Select nominal valve sizes for 200 percent of design flows. Add equivalent valve areas for two-phase flow valve sizes.

The equivalent C_v method shall not be used.

1. The fluid at the inlet shall be in an all-liquid condition, while some vapor must be present at the valve outlet. Obviously, if vapor were present at the inlet, any pressure differential taken across the valve would result in the formation of additional vapor. This restriction, requiring absence of vapor at the inlet, is imposed primarily because the valve sizing procedures are considerably more complicated when the inlet stream contains vapor. Valve sizing procedures, which will be discussed later, shall be limited to the all-liquid inlet condition.
2. The fluid at the inlet may be in either a saturated or a subcooled condition.
3. The valve outlet pressure shall be either at or below the vapor pressure of the liquid.

6. Control Valve Sound Levels

This Section includes minimum requirements for control valve sound level limitations. The requirements shall be defined by API STD 553 and MP 00-P-05 in conjunction with the following additions.

- Control valve sound level test data shall be obtained from the manufacturer when possible. Otherwise, sound levels shall be predicted using the manufacturer's methods. Full documentation covering the formulas and method of sound level predictions shall be provided.
- All valves with predicted sound levels exceeding 85 dBA (90 dBA for on/off valves), as measured 1 m (3 ft) downstream from the valve and 1 m (3 ft) perpendicular from the pipe, shall be identified as such on the valve data/specification sheet. It is recommended that all control

valves be included in the overall area sound level prediction. The sound level prediction method shall consider worst-case process conditions.

- Control valve predicted sound levels shall comply with the requirements of the recognized local regulatory agencies and project specifications.
- Source treatment shall be the primary method of control valve noise reduction unless otherwise specified. Heavy-walled piping and acoustic insulation shall be used only when source treatment cannot reduce valve noise to required sound levels.
- Diffusers are considered a source treatment method.
- Valve vendor noise suppression requirements or alternate methods shall be considered.

7. Control Valve Actuators

7.1. Subsea Applications

Special considerations are necessary for subsea applications (for example, dropped object impact and actuator maintenance).

- Subsea actuators shall be hydraulic-type only.
- For subsea service, proximity switches are preferred. If regular position switches are used, they shall be redundant. In all cases, they shall be retrievable and fitted to the actuator.
- Refer to API RP 17A. Specific examples are assembly and disassembly of the actuator for maintenance and interface of the control system.

7.1.1. Other Considerations

Other special considerations that shall be taken for subsea actuators include:

1. Water depth
2. Distance from control panel to sea level (elevation)
3. Remote Operated Vehicle (ROV) or diver installed and maintained
4. Special coating or other corrosion protection (for example, anodes)
5. Effect of distance between actuator and control source (for example, subsea umbilical)

7.1.2. Materials/Cleanliness Standards

The physical properties and chemical composition of the steels used in the manufacture of the valve actuator shall be subject to approval. Full details of

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all valve actuator materials including physical/mechanical properties together with all relevant standards shall be submitted for approval.

All welding and welding repairs shall conform to MP 57-P-02.

The hydraulic cleanliness standard shall meet NAS 1638 Class 6. The following applies:

NAS 1638	**Number of particles per 100 ml**					
Class 6	**Micron Range**					**ISO Class**
	5-15 T	15-25 T	25-50 T	50-100 T	> 100 T	
6	16k	2.8k	506	90	16	15/12

The supplier shall ensure that all actuator hydraulic components are precleaned and assembled in clean conditions compatible with achieving the specified hydraulic cleanliness standard. Any flushing or cleaning fluid used shall be compatible with the final charge of hydraulic fluid.

7.1.3. Open/Close Operations

Cyclic opening and closing of the valve actuator shall be performed a sufficient number of times to ensure correct operation for opening and closing the valve. Actual and indicated positions shall match for the following conditions:

1. With full design pressure differential across valve seats, alternating on each side of the valve.
2. Full pressure applied simultaneously on both sides of the valve.
3. Testing of the pressure balance system. It shall confirm closing and opening time, torque values and demonstrate limit and position devices after/during the test.

7.1.4. Other Testing

Pressure and time shall be recorded for both hydrostatic and hyperbaric testing using automatic recording equipment. Test charts shall be clearly identified as the date and type of test and the person supervising the test. The test shall confirm that no leakage or detrimental deformation has occurred (refer to ISA S75.19). Testing shall be witnessed and approved in accordance with the QA/QC Plan.

- Hyperbaric chamber pressure tests shall be performed on each assembled valve and actuator under water at a pressure equivalent to the project seawater depth.

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- Hyperbaric testing shall simulate equivalent collapse pressure at subsea depth.
- A shell test of the hydraulic cylinder, pressurizing through the opening port, shall be carried out at 1.5 times the design pressure. The pressure shall be held for a minimum of one hour during which time the accuracy of the end position and the indication system shall be checked.
- A pressure and temperature recorder shall monitor this test and the actuator shall be inspected for signs of internal or external leakage.
- The pressure shall be released and the test repeated with the closing port connected to the pressurizing system.
- Tests shall be carried out on each actuator to verify forces generated during the hydraulic opening stroke and also during the spring close strike. ROV override torque shall also be measured for subsea applications.

7.1.5. Hydraulic Fluid Samples

Hydraulic fluid samples shall be taken from each actuator during the testing program to confirm compliance with the specified standard.

The minimum requirements for sampling are:

- Before in-air testing
- After in-air testing
- After hyperbaric testing
- Prior to dispatch

8. Control Valve Accessories

Control valve accessories shall be procured as part of the valve assembly through a single source. All testing and inspection shall be made on the final assembly.

- Pneumatic accessories that are mounted on the control valve shall be piped by means of stainless steel tubing in accordance with MP 32-P-19.
- Split ranging signals from the control room, done with individual DCS analog outputs to each valve, are preferred. However, with approval, split ranging of valves can be accomplished locally using pneumatic relays or valve positioners.
- Cooling fins shall be provided for control valves operating at 175°C (350°F) or higher in steam service and 205°C (400°F) or higher in other services.

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- Warming spools shall be provided for control valves operating at -18°C (0°F) or lower. Special extension bonnets shall be used for cryogenic services.
- Mounting brackets and accessory hardware shall be suitable for use in the environment in which the valve is to be installed. Brackets and hardware in harsh (corrosive, marine, or tropical) environments shall be stainless steel or epoxy painted. Cadmium or electro-plated bolts or hardware shall not be used in harsh environments.
- Solenoid valves or I/P transducers for use in intrinsically safe circuits shall be certified by an approved testing agency. Solenoid valves or I/P transducers for use in non-incendive circuits shall be certified by an approved testing agency for use in a non-incendive circuit or shall carry an appropriate non-incendive or explosion-proof rating.
- Piston type actuators applied in harsh (marine or tropical) environments shall be configured as to minimize the ingress of air from the local atmosphere. A tubing, filter and check valve configuration shall be used to assure the air entering the actuator is primarily from the instrument air supply.
- Valves identified as being in critical service during P&ID reviews shall be so indicated on the P&ID and valve data sheets (see the Mobil Data Sheets for this MEP). Such valves may require fireproofing. Following are examples of valves in critical service:
  - Those in boiler feedwater service
  - Those in steam pressure letdown service
  - Valves required for a safe, controlled plant shutdown
  - Valves required to function when controlled shutdown systems fail or unsafe conditions exist

9. Marking and Coatings

- Each actuator shall be marked with a stainless steel identification plate. The actuator ID plate shall include the following:
  - Actuator type
  - Size
  - Power to open or close
  - Power range (for example, 20–100 kPa [3 psi–15 psi] pneumatic)
  - Maximum pressure rating
  - Hydraulic fluid type
  - Matching valve, make and size
- Actuator paint colors shall be the manufacturer's standard unless otherwise specified.

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- Subsea actuators may require a special type of marking–yellow/black PVC Epoxy on actuator body. Check procedures for Remote Operated Vehicle (ROV) interface to determine color coding requirements.
- Actuator paint shall be manufacturer's standard unless otherwise specified. If standard paint is not acceptable, refer to MP 35-P-01.

10. Documentation and Data Sheets

- The contractor shall furnish control valve, pilot and regulator data sheets (see the Mobil Data Sheets for this MEP and for MP 32-P-08) and control valve calculations as they are completed.
- The contractor shall furnish detailed printouts containing actual process data, calculated sizing, sound level results and formulas for approval before purchase.
- On request, the valve supplier shall furnish all documentation required for valve maintenance.

11. Inspection

Control valve purchase specifications shall provide for inspections. Some or all aspects of inspections may be waived through established purchase agreements. In these cases, documentation noting the waived items shall be provided.

11.1. Inspector/Agent

The inspector or agent shall:

1. Inspect and test all compressor anti-surge control valves
2. Choose other valves at random over the entire production run
3. Check all items or any part thereof or request all tests or any portion thereof

The checklist for control valves, given in the Appendix, shall be completed for each valve inspected and shall become part of the inspection documents.

12. Testing

Some or all aspects of testing may be waived through established purchase agreements. In these cases, documentation of the items waived shall be provided.

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Leakage tests for valves in leakage classes III, IV, V and VI, as defined in FCI 70-2, shall be conducted by the valve manufacturer and witnessed by the inspector or agent.

- All safety shut-off valves and valves for tight shut-off service shall be tested for maximum seat leakage in addition to the requirements of the Appendix. An acceptable test procedure is outlined in FCI 70-2.
- Single-seated valves for safety shut-off service shall meet Class V requirements: 0.0005 cm^3/min/in NPS (nominal pipe size) maximum.
- Single-seated valves in other tight shut-off services shall meet Class IV requirements: 0.01 percent of rated valve capacity maximum.
- Double-seated valves shall not be used for these services.

13. Modifications to API STD 553

The following sections include modifications to API STD 553. Numbers correspond to the section and paragraph numbering within that standard and reflect additions, substitutions, modifications and deletions.

3.1. Addition: Materials of Construction

Valve trim shall be Type 316 stainless steel unless process conditions require a higher grade or special materials. Valve trim includes plug, seat rings, valve plug stem, stem lock pin, packing spring, lantern ring or spacer and packing follower. Project or facility piping and material specifications shall be referenced to aid in the selection of control valve trim materials.

3.1.1. Addition: Pressure Containment

Casting requirements shall comply with MP 03-P-02, unless otherwise approved.

3.1.4. Addition: End Connections

Flanged end connections shall be used for all globe-style body sizes larger than NPS 1 (NPS = nominal pipe size, inches).

- Control valves with NPS $1^1/_4$, $2^1/_2$, $3^1/_2$ or 5 connections shall not be used.
- Threaded connections shall be internally tapered threads in accordance with ASME B1.20.1.

3.1.6. Addition: Precautions

Flangeless valves installed with elongated bolts are not recommended for toxic or flammable service. Minimum requirements for bolting shall be Grade B7 as reflected in ASTM A193/A193M REV B. If specific applications require this valve configuration for

toxic or flammable service, it shall require approval. The valve, bolts and pipe flanges shall be fireproofed in all such applications.

3.1.7. Addition: End Connections

Flange facing finish shall conform to ASME B16.5.

3.1.13. Addition: Packing

Control valve packing glands shall be the bolted type, except in sizes NPS 2 and smaller.

Packing follower and packing gland bolts shall be Grade B8M (as reflected in ASTM A320/A320M REV A) stainless steel in sweating or cold (less than 0°C [32°F]) service. The packing gland bolt torque specified by the valve manufacturer shall be included as part of the valve specification sheet information.

The valve packing material and the valve packing assembly shall be determined by their application. In particular, the following points shall be considered:

1. Estimated packing box temperature (related to bonnet design, process fluid temperature, valve flowrate, insulation and tracing)
2. Process fluid pressure
3. Process fluid compatibility with packing material
4. Valve environmental emissions requirements
5. Hazardous process fluids applications
6. Vacuum service
7. Valve type and configuration
8. Packing/valve stem friction limitations as related to hysteresis
9. Packing seal integrity in a fire

The recommended packing for general service with moderate packing box temperatures to 350°F is TFE V-ring. Note that compound pressure service requires double packing with one set inverted. This form of packing is, in most cases, spring loaded and the V-rings are of a relatively thin cross section, making it less tolerant of high temperature and pressure fluctuations. Packing box temperatures shall be conservatively below the manufacturer's recommended limitations. For temperatures to 400°F or where pressure fluctuations make TFE V-ring type packing inappropriate, TFE compounds reinforced with glass or Kevlar fibers shall be used.

Temperatures above 205°C (400°F) require graphite compounds. The recommended configuration is braided graphite rings top and bottom, with flexible graphite (minimum uncompressed density 1360 kg/m^3 [85 lb/ft^3]) between them. When flexible graphite is used alone, sealing washers are recommended for each end of the packing box to prevent excess packing material extrusion. Braided graphite asbestos is a functionally acceptable alternative for high-temperature service where asbestos is permitted by local authorities.

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Bonnets on all control valves shall be tapped for the addition of lubricators and steel isolating valves for all control valves with packing other than TFE asbestos and Grafoil. Lubricators shall be charged with suitable lubricant and a spare box of refills shall be provided with each valve. All valves with extended stems require lubricators.

3.1.14. Addition: Packing

Bellows seals or special environmental packing systems shall be provided for environmental emission control applications, keeping process emission levels within the EPA standards defined in the National Emission Standard for Equipment Leaks (Fugitive Emission Sources). Refer to 40 CFR 61 Subpart V.

3.1.15. Addition: Seat Leakage

Worst-case process conditions shall be considered for control valve leakage class selection.

Actuator type and size shall be selected to provide adequate seat loads for the selected leakage class on a conservative basis (10 percent above the minimum calculated thrust per inch of port circumference). The primary criteria for meeting tight shutoff/low leakage requirements shall be proper trim design configuration and materials.

Single-seated control valves or other types whose test results indicated equal or better shut-off characteristics, shall be used when tight shut-off is desired. Composition seats for shut-off valves may be used when tight shut-off is desired and when they conform to the pressure, temperature and chemical limitations of the process.

- Double seated valves are not recommended for tight shut-off service.
- Factory plug/seat lapping procedures are acceptable when offered as a vendor standard.
- Single-seated control valves with springless top works and double-acting pistons may be used, with approval, for tight shut-off and where extra power is required to overcome unbalanced forces caused by process operating pressure and shut-off pressure.

3.1.16.c. Addition: Flow Characteristics

The installed control valve flow characteristic shall meet process control requirements. Theoretical valve flow characteristics are defined under ideal conditions of constant pressure drop. The relationship between usable pressure drop and flowrate shall be examined in order to determine the actual installed characteristic.

3.1.17. Addition: Globe Valves

Where conditions allow, the valve with the most efficient flow path and higher C_v per square inch port ratio shall be considered.

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- When tight shutoff is not required, unbalanced constructions shall not be used if oversized topworks are necessary to overcome pressure drop forces. In such cases, doubleseated, cage trim or other balanced valves shall be used.
- Cage guided and bottom-guided trims shall not be used in waxy or solid bearing service or in slurries or gas services containing particulates (e.g., fuel gas).
- Skirt-guided plugs shall not be used, except that sizes NPS $1^1/_2$ and smaller in low differential pressure service may be submitted for approval.
- Cage guided valves with balanced trim are recommended for high-pressure drop service where moderate leakage rates can be tolerated.
- Cage guided valves with special seals may be used where both low leakage rates and low noise/cavitation control trim is required.
- Single-port top and bottom guided valves are recommended for high-pressure drop service in clean nonsolidifying fluids.
- Top guided single-port valves are acceptable for moderate pressure drop service, provided the guide bushing is of sufficient length and diameter.
- Skirt and stem guided valves shall not be used in high or moderate pressure drop service.
- Extension bonnets shall be used in cold temperature service 18°C (-0.4°F) and below and high-temperature service above 350°C (660°F). Warming spools in conjunction with extension bonnets may be required for cryogenic service.
- High temperatures and temperature cycling can present problems with large cage guided, high-energy trim. The high-energy cages in large valves tend to be longer than standard cages and are subject to linear thermal expansion. Under these conditions, a floating cage construction shall be provided. Unlike standard cages, the floating cage is clamped at one end only and has "deformable" seals at the opposite end. Valve body distortion can also occur in high-temperature differential service such as cyclic regeneration of high-pressure reactors.

3.1.18. Addition: Sizing Methods

Valves shall be sized for 100 percent of capacity using the selected vendor's methods. These methods shall agree with ISA S75.01.

- For intermediate capacity indexes and/or stem position, the vendor's published tables or test curves may be used.
- If the selected vendor has no published tables or test curve of intermediate positions, data or curves of an equivalent vendor may be referenced, provided the competitor's valve is completely identified.
- If no competitor manufactures an equivalent valve, the vendor shall be required to furnish a table or test curve showing capacity index versus stem position for the 1, 10, 50, 70, 90 and 100 percent capacity index points.

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- The selected vendor's valves with the same capacity index ratings, as noted herein, shall be used.

Proprietary computer programs for valve sizing are acceptable, provided detailed printouts containing original data, calculated results and formulas are submitted for approval. Special or proprietary design valves shall be sized in accordance with the manufacturer's formulas. These calculations, formulas and symbols are subject to approval. The valve rated C_v shall be selected so that:

1. The valve C_v is no greater than 200 percent of normal flow C_v.
2. The installed rangeability of the valve under the worst-case pressure drop conditions will allow stable control within the maximum and minimum flow ranges.

Control valves for depressuring to flare lines shall be sized to prevent overloading the flare system. For special process considerations (e.g., an exothermic reaction that requires depressurizing within a finite time), the depressuring valve shall be designed to maintain a fixed, minimum flow with a decreasing pressure.

Where the calculated control valve body size is two or more sizes smaller than line size, a valve body one size smaller than line size with reduced inner valve trim shall be used. Smaller body sizes may be used, subject to approval, where availability of reduced trim is limited.

The critical pressure ratio Pc/P1, shall be assumed to be 0.50. API publications or other recognized handbooks shall be used to obtain the correct ratio.

The capacity index C_v shall be used for non-compressible fluid flow. The capacity index C_s may be used for steam, C_g for other compressible fluids (gases) or C_v for both.

- Where C_v is used for steam or compressible fluids, the formula to obtain C_v shall be shown on each data sheet and/or calculation sheet (or state that ISA sizing equations apply).
- Modifying factors may be necessary to bring the index into reasonable agreement with actual test flows. The correction factors for each service and valve configuration shall be shown on the calculation sheet and/or data sheet.
- For valve configurations used with non-compressible fluids not covered in tables or for which there are no available test curves, complete documentation, including reference papers, shall be furnished.

Each valve shall be sized considering its individual application such as:

- Maximum operating flow with minimum energy loss while maintaining stable control
- Minimum operating flow with corresponding higher pressure drop
- Speed of response of the associated control loop
- Projected magnitude of control loop disturbances
- Loading of downstream processes including relief and flare systems

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Control valves in feedwater service to hot-water or steam generators shall be sized on the basis of the Maximum Continuous Rating (MCR) of the generator plus the design continuous blowdown rate. Maximum downstream pressure shall be the generator design pressure or the steam drum safety valve setting, whichever is higher.

When the process control requirements exceed the practical rangeability of a single control valve, two control valves operating in parallel shall be provided. The inherent flow-lift characteristics and the rated C_vs of the two valves shall be chosen to provide:

- A smooth combined flow-lift characteristic
- Proper control of the lowest specified flowrate

The larger of the two valves shall provide tight shutoff. The split range of the two-valve combination shall be selected to ensure a "bumpless" transfer from one valve to the other.

3.1.18. Addition: Rangeability

The operating range for a conventional globe, split body or double/single-seated valve shall be 10–90 percent of the associated capacity index (C_v) for the particular valve. This requirement applies to control valves with a published range of 25 to 1 or better at constant pressure drop. A table published by Fisher Controls International indicates that for an equal percentage valve, 75 mm (3 in) with a 50 mm (2 in) reduced port, the capacity index, C_v, is 52.8 at 90 percent opening and the C_v is 2.01 at 10 percent opening, resulting in a published range of 25.77.

- If the valve is oversized for an initial process flow condition, then reduced trim shall be used until the design production rate is met.
- All control valves in services not specified herein shall be sized for a flow rate of twice the operating flow rate. Where the maximum flow rate is more than twice the operating flow rate, the maximum flow rate times 1.10 shall be used. For sizing, the design differential pressure shall be 50 percent of the system friction drop, exclusive of the control valve at the maximum flow rate.
- In specific applications where twice the operating flow rate could be hazardous, the maximum flow rate shall be set by equipment design considerations; for example, where twice the operating flow rate might result in too great a heat flux in a furnace.

3.1.18.d. Addition: Piping Influence

When a valve is installed between adjacent reducers, a correction factor shall be included in the basic valve calculation for both noncritical and choked flow. The manufacturer's recovery coefficients shall be used (see also ISA 0-87664-234-2, Chapter 6).

A minimum of 10 pipe diameters shall be provided upstream and downstream of a valve with noise-reduction trim before turns (elbows) or obstructions (check valves, strainers, etc.).

For standard trim, sufficient upstream and downstream straight length for control valve installation shall be provided to minimize flow pattern disturbances. A control valve installed between a pair of elbows and reducers with no additional straight-run spacing

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can result in extreme vibration at maximum flow. The flow jet from the valve port does not have sufficient distance to dissipate before it enters the elbow. To minimize this problem, full line-size spools, each equivalent in length to the face-to-face dimensions of a line-size block valve, shall be included on either side of the installed valve.

For high-capacity, high-recovery control valves, the installed valve C_v shall not exceed the value of the inside diameter of valve body outlet port in inches squared by more than a factor of 30; that is, C_v shall be less than 30 d^2. High capacity valves shall not be used in piping systems longer than 600 m (2000 ft). Refer to ISA 0-87664-234-2, Chapter 6, and MP 16-P-01.

3.1.18.f. Addition: Pressure Recovery

In normal valve sizing calculations where pressure conditions for valves have already been fixed and where it cannot positively be determined by inspection that cavitation or flashing will not occur, the choked flow equation shall be used. Refer to ISA S75.01.

3.1.18.g and h. Addition: Flashing and Cavitation

Where it is obvious that cavitation or flashing will occur and ISA S75.01 does not apply, the sizing method used shall be fully documented for approval.

3.1.21. Addition: Dead Band

Dead band is a major contributor to excess process variability and control valve assemblies are often the primary source of dead band in an instrumentation loop. Dead band is the range through which an input signal may be varied, upon reversal of direction, without initiating an observable change in the output signal. Dead band of the control valve assembly is determined by a series of open-loop tests while the control valve is dynamically loaded.

- Dead band of the control valve should be less than 1 percent for regulatory process control. Dead band of less than 1 percent should be expected in control valves with PTFE packing, properly sized actuators and reasonable positioner gains. A high performance positioner is needed to assure this type of dead band performance. If live-loaded and/or graphite-type packings are used, an adjustable gain digital positioner is required to achieve dead bands of less than 1 percent.
- In many process applications, such as advanced process control, the control valve is required to move for signal changes less than 0.5 percent. These applications require the use of the adjustable gain digital positioners.
- In applications not requiring strict regulatory process control, dead band of the control valve should be less than 3 percent.

3.2. Addition: General

Loading relays shall not be used to increase stem force in lieu of larger topworks. Any combination of loading relay and topworks requires approval.

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The valve supplier's standard method for actuator sizing may be used only after sample calculations have been approved.

- Valves without positioners operated by controllers that inherently have their output clamped at 4 mA and 20 mA shall have actuators sized and adjusted for full travel and full seating force for this range.
- Valve position indicators shall be supplied on all valves. Two-way valves shall indicate position on a graduated scale with the words "open" and "shut" marked at the travel limits. Three-way valves shall indicate stem travel without the words "open" and "shut," and the common port shall be identified. Rotary valves shall indicate valve position with a highly visible position indication beacon (Westlock or equal).
- Other actuators, such as hydraulic or electrical types, may be used where air or instrument gas is not available or due to design or space requirements, subject to approval.
- Manual override operation of the actuator is required for all critical services. Examples of these services are the emergency shutdown valve (ESDV) system and specific variables (for example, backpressure, flow and relief systems). This manual override shall not interfere with normal valve operation nor act as a "stop."
- Instrument tubing shall be a minimum of Type 316 seamless as specified by ASTM A213/A213M REV A and ASTM A269. Corrosive services may require other materials (e.g., Monel).
- The preferred fittings are compression-type. The use of double or single ferrule shall conform to project or site standards. The use of double ferrule fittings shall be considered where the fitting or associated tubing will be subjected to excessive vibration or mechanical stress. Corrosive services may require other materials (for example Monel). Also, pressures above 10,000 psi require the use of special fittings. Welded tubing can be used with approval.
- The valve vendor shall be responsible for inclusion and integration of the actuator selected.
- The use of electrical (motorized) valve actuators is limited to gate valves.
- All material used in construction of the actuator shall be compatible with the gas or hydraulic operating fluids and contaminants found in the local environment.
- Where practicable, all valves in a specific installation shall have similar-type actuators.
- Critical valve actuators shall be firesafe and failsafe.

The valve actuator manufacturer shall supply all information required to verify the actuator type and size selection. This shall include:

1. Effective diaphragm area
2. Stem diameter
3. Unblanced plug area

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4. Spring rate
5. Packing friction
6. Bench set (inherent diaphragm pressure range)
7. Required seat load to meet leakage specification
8. Drag due to trim piston rings
9. Predicted valve installed diaphragm pressure range
10. Formulas utilized
11. Stroke length and speed
12. Hysteresis curves/graphs

3.2. Addition: Materials of Construction

Valve actuator springs shall be carbon steel with factory-applied, rust-resistant coating. For corrosive atmospheres, alloy springs shall be considered.

3.2.3. Addition: Actuator Selection

Pneumatic spring-diaphragm or spring-return piston actuators, operating on instrument air, shall be the preferred mechanism for operating control valves. Valves specified with pneumatic positioners shall have pneumatic spring-diaphragm actuators operating on 20–100 kPa gauge (3–15 psig) instrument air.

The minimum and maximum pressures of the gas or hydraulic operating fluids applied to the valve actuator shall develop a thrust sufficient to conservatively comply with specified acceptable valve leakage and overcome all unbalanced forces acting on the valve plug and stem (when the greatest differential pressure possible in the system is across the valve). The valve spring force shall be added or subtracted to this thrust, depending on the direction of the spring force. In addition to these forces, allowances shall be made for hysteresis in the movement of the valve components and the weight of the moving parts.

- Piston or cylinder actuators are preferred where valve designs with long strokes are required. The piston or cylinder can be operated hydraulically or pneumatically.
- Diaphragm-operated valves shall be installed in the vertical upright position. Mounting of actuators in a horizontal position requires approval; the need for supports to prevent distortion or bending the valve stem shall be studied.
- Where pneumatic actuators can become too large for the available space, hydraulic actuators shall be considered.
- Hydraulic actuators shall be used for very large valves requiring high forces or where very precise valve actuation is required.
- Isolating valve services' on-off position actuator shall be designed to operate with a maximum of 833 kPa (125 psi) pneumatic supply.

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- Hydraulically-operated valves in safety shutdown service shall not share the hydraulic power system with valves in conventional services.
- Each hydraulic system shall be a completely fabricated, piped and wired skid-mounted unit.
- Double-acting, springless opposed piston actuators shall use positioners and shall use volume tanks to implement fail-safe position requirements.

3.3. Addition: Positioners

Positioners are required on all control valves, springless actuators and push-pull pistons.

- Smart positioners shall be used unless otherwise specified.
- Installation and calibration of positioners shall be done in the valve vendor's shop.
- Valves in on-off service do not require positioners.
- Electropneumatic positioners are recommended for most applications. In critical loops, where downtime for positioner failure is not acceptable, pneumatic positioners with bypass and remotely mounted I/P converters shall be used. The bypass mode shall permit servicing of the positioner without taking the valve out of automatic service.
- Direct or reverse action shall be attainable on all positioners with simple field adjustments.
- Installation and calibration of positioners shall be performed by the valve manufacturer.
- Positioners shall not be used as a means for changing the valve flow characteristic unless approved.

Gauges on pneumatic positioners shall indicate supply pressure, control signal and positioner output.

- Gauges on electropneumatic positioners shall indicate supply pressure and positioner output.
- Pressure gauges shall be made of stainless steel and sealed against the environment. Internal parts shall be made of brass (as a minimum).

3.4. Addition: Handwheels

- Handwheels shall be side mounted unless otherwise approved. All control valves shall have an auxiliary, manual means of controlling the flow, unless safety considerations preclude the use of such means.
  - For control valves larger than NPS 2, handwheels for manual control shall require approval.

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  - For control valves NPS 2 and smaller, a three-valve bypass manifold is required (refer to Additions to Paragraph 5.3 given in this MEP).

- Handwheels shall not be used as travel limit stops.

- Handwheels shall be easily operable from normal personnel access paths or platforms. Handwheels shall face the operator access area and the shaft center shall be 1–1.5 m (3–5 ft) above the elevation of the access area. When valve actuator configurations or piping layouts preclude this arrangement, a supplemental platform is required.

3.5.1. Addition: Limit Switches

Positive valve movement (open/close) shall be indicated by using, as a minimum, single pole double throw (SPDT) hermetically-sealed position switches. A local valve stem position shall be included.

Magnetic, inductive or capacitive type switches with valve position indication are preferred.

- Mechanical limit switch and linkage devices used to detect valve stem position shall not have a dead band exceeding the lesser of 10 percent of the valve travel or 3 mm (0.125 in). Rotary valve limit switch dead band shall not exceed 5.0 degrees rotation of the valve disk shaft.

- Mechanical limit switch mounting brackets to valves shall be robust to prevent switch trip settings from deviating.

- All switch parts shall be protected from corrosion.

3.5.2. Addition: Solenoid Valves

Solenoid valve coils shall use Class F coil insulation as a minimum and Class H coil insulation for emergency shutdown service and critical valve service. Refer to NEMA MG 1, Section 1-1.65, "Classification of Insulation Systems," for details on operating temperature ranges and materials of construction.

Solenoid valves shall not be used for process (wetted) service without approval.

Solenoid valves shall be either direct mounted or supported from a mounting bracket. The tubing shall not be used as a means of support.

3.6. Addition: Transducers

- The standard I/P transducer shall have a 4–20 mA DC input gauge and a 20–100 kPa (3–15 psig) output gauge. Other output signals may be used with approval.

- Current to pneumatic (I/P) transducers shall be purchased with factory connected or integral air pressure regulators.

- Transducers shall not be mounted on valves in high-pressure drop service, flashing/cavitating service and in locations subject to vibration from associated equipment or adjacent piping.

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- Transducer enclosures/cases shall be NEMA 4X minimum.
- The loading and venting capacity of the transducer shall not limit the valve response time.

3.7.1. Addition: Booster Relays

Volume boosters used to increase stroking speed shall have sufficient venting capacity to provide equal response in the loading and unloading directions. Boosters with undersized vent orifices tend to make actuator stroking speed asymmetrical, resulting in unstable control.

Volume booster relays shall be used for all pneumatic transmission distances greater than 46 m (150 ft) when there is not a positioner.

4.1.3. Addition: Three-Way Valves

Three-way valves are frequently used for mixing and diverting in temperature control applications.

Three-way valves shall be clearly and permanently marked to indicate inlet/outlet connections and flow proportioning as a function of stem position.

4.2. Addition: Butterfly Valves

- Butterfly valves of heavy pattern design shall be used.
- Disk attachment shall be done by double pinning to a solid shaft.
- Butterfly valves in slurry service or in liquid service with entrained solids shall be mounted with the valve shaft in the horizontal position (or as recommended by valve supplier for other services).
- The shear safety factor shall be 2:1 at maximum shutoff pressure across the valve. The limiting value shall be taken at the weakest point, such as pins or keyways.
- Butterfly valves that have been modified by having holes cut in the disks shall not be used. Control characteristics of such valves cannot be predicted.
- Butterfly valves in hydrogen, HF and sulfuric acids, hydrocarbon light ends, H_2S, caustic and other hydrocarbons, acids and toxic services shall require blowout protection. Valves in nonhydrocarbon services (i.e., high-pressure steam, water, air, etc.) that can do damage or personal injury due to their location shall also be evaluated for blowout protection.
- Butterfly valve shaft retention thrust collars for blowout protection shall be fitted to valve shaft ends opposite to the actuator and open to atmosphere if the valve does not meet API STD 609, Paragraph 2.5.1:

  > "The shaft shall be designed so that if failure of the shaft-to-disc connection or internal failure of the shaft occurs, no portion of the shaft can be ejected from the valve as a result of internal pressure."

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4.2. Addition: Ball Valves

Contoured ball valves shall be considered for slurries and erosive service. They have a high rangeability and are cost efficient for low to moderate pressure drop, nonhazardous service.

Ball valve stem retention shall not depend on the packing gland. A shouldered stem with bottom entry is preferred.

4.2.1. Addition: Eccentric Spherical Plug Valves

Eccentric (disc) spherical plug valves have advantages over butterfly valves: greater rangeability, tighter shutoff and, generally, the ability to handle a higher pressure drop. This type valve in flammable or toxic service requires integral flanges.

5.0. Addition: Precautions

Control valves shall be removed from the piping system during flushing and hydrotesting.

5.1. Addition: Accessiblity

All control valves shall be installed so that the valve and associated accessories and indicators are readily accessible to maintenance and readable from normal personnel access paths. Control valves may be mounted above grade if a platform for access is provided.

Where only one side of the control valve is accessible, the travel indication scale and accessories (i.e., positioners, hand wheel, solenoid valves, limit switches) shall be mounted to be readable and maintainable from normal operator access areas.

5.3. Addition: Control Valve Manifolds

Control valves in slurry or dirty service shall not have blocks and bypasses where deposits can build up in the bypass line.

Control valves shall be equipped with an auxiliary method for bypassing the control valve or manually operating the control valve. The method of manual control shall require approval.

- Block and bypass valves shall be used around all control valves in lines of NPS 2 and smaller and also those valves in critical service. Control valves without a bypass shall be equipped with a handwheel.
- Where blocks and bypasses are used, blocks shall be of line size and bypasses shall have a port equal to one size larger than the control valve.

Emergency shutdown valves requiring periodic in-line testing that cannot be met by scheduled plant turnarounds shall have line-size blocks and bypasses. With approval, emergency shutdown valves may be ball valves with actuators that are pinnable for partial

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travel testing as an alternate for blocks and bypasses. Emergency shutdown valve design and configuration shall be based on the shutdown system's required safety integrity level.

7.5.1. Addition: Precautions

Control valves shall be located so that topworks, accessories or other applicable components are not in close proximity to high-temperature sources. The actuator and accessories shall have a minimum clearance of 600 mm (24 in) from surfaces exceeding 260°C (500°F). Where this clearance is not available, thermal shielding shall be used.

As a minimum, valve bodies shall be carbon steel. Cast iron shall be used only with approval. Recommendations regarding other body materials shall be subject to review and approval.

Bolting for valve bonnets shall be stainless steel in service temperatures less than 0°C (32°F). Other bolt material requirements shall comply with MP 16-P-31A. Hardened trim (i.e., plug and seat) shall be used for flashing liquids, fluids containing solids, valve pressure drops exceeding 1400 kPa (200 psi) and services above 310°C (600°F), unless higher grade materials are required for process conditions. Tungsten carbide trim shall be used for the oil and water level control streams from the first stage production separation and from test separators.

The manufacturer shall certify that all wetted parts are from materials of known and traceable composition. The manufacturer shall provide Positive Material Identification (PMI) procedures on request.

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Appendix: Inspection Checklist for Control Valves

Item		Yes	No
1.	Has the data plate been installed with correct information?		
2.	Is the actuator action correct?		
	(a) Air to open?		
	(b) Air to close?		
3.	Do materials of construction agree with approved vendor's data sheet?		
	(a) Body		
	(b) Seat rings		
	(c) Valve plug		
	(d) Valve plug stem		
	(e) Packing flange, nuts, studs, spring packing wiper ring		
	(f) Seal bushing (if any)		
	(g) Actuator stem, extension seal (if any), stem connector, yoke, travel indicator, diaphragm or piston spring (if any), springseat (if any)		
	(h) Butterfly valve retention thrust collar		
4.	Is positioner or pneumatic relay (or both) mounted and piped correctly?		
5.	Is current-to-pneumatic transducer or solenoid valve (or both) mounted and piped correctly (compressor anti-surge valves)?		
6.	Have extension bonnet, cooling fins and bellows seal been specified?		
7.	Has body size been specified?		
8.	Has inner port size been specified?		
9.	Has type (single seat, double seat, other) been specified?		
10.	Has characteristic (equal percentage, linear, quick opening, modified parabolic) been specified?		
11.	Is the direction flow arrow correct?		
12.	Is the bench set calibration as prescribed?		
13.	Has hydraulic test been provided for the following items?		
	(a) Pinhole leaks, body leaks		

Item		Yes	No
	(b) Flow holes in interior of casting		
	(c) Shutoff against line pressure		
	(d) Tight shutoff valve leakage, in accordance with FCI 70-2		
	(e) Packing box/packing gland leakage.		
14.	Has operation of the handwheel been specified?		
15.	Has valve closure test been specified?		
	(a) Standard closing time		
	(b) Fast closing time (if required)		
	(c) Fast closing time and slow opening time (if required)		
	(d) Fast opening time (if required)		
16.	Have hysteresis limits been specified?		
17.	Is grease fitting, where applicable, properly installed?		
18.	Do valve accessories have the required intrinsic safety certification plates or identification?		
19.	Do valve accessories meet all requirements of this Practice or project specifications where more stringent?		
20.	Is the valve specified for oxygen service?		
	(a) Oxygen clean requirement observed during assembly		
	(b) Tagged and packed for oxygen service		

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Electrical - Intrafacility Communication Systems and Alarm Systems

MP 33-P-32

June 1998

Scope

This Mobil Engineering Practice (MEP) provides guidelines and identifies factors to be considered in establishing design criteria for intrafacility communications systems, including voice communications, data communications and alarm communications systems. It is intended that this MEP and the MEPS listed in the Reference Section be supplemented by project instructions to fully define the specific requirements for each facility.

Version 0

Table of Contents

Scope **1**

1. References **5**

1.1. MEPS–Mobil Engineering Practices 5

1.2. CFR–U.S. Code of Federal Regulations 5

1.3. IEEE–Institute of Electrical and Electronics Engineers 5

1.4. NFPA–National Fire Protection Association 5

1.5. Miscellaneous 6

2. General **6**

2.1. Equipment and Materials Requirements 6

2.2. Facilities 7

2.3. Physical Requirements 7

2.4. Surge Protection 8

2.5. Cabling 8

2.6. Licensing 9

2.7. Compatibility 9

2.8. Expandability 9

2.9. Towers 9

3. Voice Communication Systems–Offshore **9**

3.1. Two-Way Radio 10

3.2. Paging System 10

3.3. Intercom System 11

3.4. Sound-Activated Telephone Systems 11

3.5. Crane Communications 11

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3.6. Construction Site Communications 12

4. Communications Systems–Onshore 12

4.1. General 12

4.2. Telephone Systems 13

4.3. Radio Paging Systems 14

4.4. Radio Communications Systems 14

4.5. Special-Purpose Transmitter Systems 17

5. Data Communications Systems 18

5.1. Applications Supported 18

5.2. Protocols 18

5.3. Compatibility 18

5.4. Bandwidth 18

5.5. Physical Limitations 18

5.6. Instrument Loops 19

6. Alarm Communication System–Offshore 19

6.1. General 19

6.2. Design 19

6.3. Number and Location 19

6.4. Signals 19

6.5. Manual Alarm Initiation 19

6.6. Priority 20

6.7. Reset (Silence) Buttons 20

6.8. Interfacing 20

7. Alarm Communication System–Onshore 20

7.1. Design Criteria 20

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7.2. Acknowledgement..... 21

7.3. Equipment Requirements 21

7.4. Alarm Conditions..... 21

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1. References

The following publications form a part of this Practice. Unless otherwise specified herein, use the latest edition.

1.1. MEPS–Mobil Engineering Practices

MP 32-P-07	Safety Interlock Systems and Alarms
MP 32-P-21	Wiring for Instrumentation and Digital Systems
MP 33-P-01	Electrical - General Requirements
MP 33-P-26	Electrical - Equipment Grounding and Bonding
MP 41-P-72	Pedestal Mounted Revolving Cranes

1.2. CFR–U.S. Code of Federal Regulations

33 CFR 140	Subchapter N, Navigation and Navigable Waters, Outer Continental Shelf Activities

1.3. IEEE–Institute of Electrical and Electronics Engineers

IEEE 802.3	Information Technology - Telecommunications and Information Exchange Between Systems - Local and Metropolitan Area Networks - Specific Requirements - Part 3: Carrier Sense Multiple Access with Collision Detection (CSMA/C
IEEE 802.5	Information Technology - Telecommunications and Information Exchange Between Systems - Local and Metropolitan Area Networks - Specific Requirements - Part 5: Token Ring Access Method and Physical Layer Specifications IEE

1.4. NFPA–National Fire Protection Association

NFPA 70	National Electrical Code 1996 Edition Errata #1; Tentative Interim Amendment 1996

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1.5. Miscellaneous

AT&T PUB 350-060: Telecommunications Electrical Protection

2. General

The design criteria for intrafacility communications systems, including voice communications, data communications and alarm communications systems shall be in accordance with requirements of this MEP, unless superceded by more stringent local regulations.

The references and requirements of MP 33-P-01 shall apply to this Practice.

2.1. Equipment and Materials Requirements

Communications equipment and materials shall be designed, manufactured and tested in conformance with the following standards and regulations.

2.1.1. Installation Within the United States

For installation within the U.S., comply with the following:

- Governing standards and regulations of the National Electrical Manufacturers Association (NEMA)
- Underwriters Laboratories (UL)
- Factory Mutual (FM)
- Canadian Standard Association (CSA)
- Local codes or regulations

2.1.2. Installation Outside the United States

For installation outside of the U.S., comply with the more stringent of the following:

- Governing standards and regulations of the country in which the equipment is manufactured or shall be installed
- The standards and regulations that apply within the United States

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2.2. Facilities

Communications facilities shall meet or exceed the requirements of the following codes and regulations.

2.2.1. Within the United States

- NFPA 70
- Federal Communications Commission (FCC) regulations
- Local codes and regulations

2.2.2. Outside the United States

- Codes and regulations of the locality where installed
- NFPA 70 in the absence of recognized codes or regulations

2.2.3. Hazardous Locations

Communication equipment shall be certified by a nationally recognized testing laboratory. Labeling shall indicate rating agency and type of certification.

2.3. Physical Requirements

- Systems that are determined critical to safe and efficient operation of the facility shall be provided with a UPS system or a battery backup to ensure normal operation in the absence of AC power.
- The communications systems shall be located in a suitable environment, as required for safe and reliable operation of the equipment. Communications systems normally require an indoor location, temperature control and absence of corrosive or flammable gas concentrations.
- When designing a stand-alone building and/or facility housing a communications system, the reliability of incoming power and the effect of heat generation of the system shall be evaluated. Supplemental air conditioning may be required.
- The system design shall minimize the amount of equipment located in hazardous environments. Equipment located in hazardous locations shall be certified by a nationally recognized testing laboratory.
- The communications systems shall be adequately grounded. Equipment grounding shall meet the requirements of MP 33-P-26.

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2.4. Surge Protection

Communications system design shall take into consideration all sources of electrical disturbances. This shall include exposure to lightning, contact with power sources or inductive interference and rising ground potential. Design shall assure that adequate surge protection is provided. Grounding shall meet the requirements of MP 33-P-26 and AT&T PUB 350-060.

As a minimum, surge protection shall be installed:

- Where the incoming AC power enters the system
- At each end of communications cables that have lengths greater than 30 m (100 ft)
- Where conduits are not enclosed by adequately grounded rigid metal conduit or metal cladding

2.5. Cabling

- Cabling system design shall be suitable for the intended application.
- Communications systems manufacturer's cabling specifications shall be consulted before cable is selected. Sufficient spare cable capacity shall be included in the initial design.
- Communications cable shall be selected for the application and suitable for the type of installation (in raceway, direct burial, overhead, cable tray, etc.) and shall conform to MP 32-P-21.

2.5.1. Critical Communication Circuits

- Cables associated with critical communication circuits (voice, alarm, power) shall be high-temperature cables rated for 2000°F for 60 minutes or adequately fire-proofed to achieve a 60 minute fire rating.
- Onshore in refineries and chemical plants, the preferred method for communication circuits designated as critical circuit cable shall be installation in rigid galvanized steel conduit.
- Offshore and in gas plants, communication circuits designated as critical circuit cable shall be armored and installed in stainless steel tray.
  - Critical circuits shall be physically isolated from other circuits.
  - Isolation shall prevent contamination of critical circuit cables by other cables and supports that are subject to failure during a fire.
  - Where tray application is not practical, cable shall be installed in PVC coated rigid galvanized steel conduit.

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2.6. Licensing

Radio Frequency (RF) communications shall require a license from the authority having jurisdiction. Licensing requirements need to be identified as early as possible, since receiving final approval of an RF license can be a lengthy process. Mobil has established procedures for acquiring licenses and the appropriate specialists shall be consulted.

2.7. Compatibility

All system components shall be compatible. Compatibility testing is required if more than one manufacturer's equipment is used.

- Equipment shall be standardized with existing communications systems, assuming equipment is readily available and is functioning as required.
- Intrafacility communications systems shall be compatible with external communications systems.
- Mobil shall ensure that adequate support is available to administer all communication systems.
- All communication equipment installed in hazardous locations shall be certified by a nationally recognized laboratory. Labeling shall indicate suitability for use in classified locations or intrinsic safety.

2.8. Expandability

The systems shall be readily expandable to a level that shall account for reasonably anticipated growth.

2.9. Towers

If a communications tower is required, the vendor shall provide Mobil with the relevant technical details. Communications tower design and installation is outside the scope of this MEP.

3. Voice Communication Systems–Offshore

The facility voice communications requirements shall be identified prior to system design. These requirements may include one or more technologies, or may use other technologies not described herein. Administrative communications requirements, for example office telephones, office paging systems, etc. are outside the scope of this MEP, but shall function in conjunction with the facility communications system specified herein and, in many cases, shall function as one system.

3.1. Two-Way Radio

A two-way radio system shall be used where members of a mobile work force converse frequently, but only briefly, with one another.

- System design shall consider the anticipated radio wave propagation characteristics within the proposed facility.
- The project engineer shall consult with corporate or affiliate (if applicable) telecommunications personnel to initiate license procurement. Mobil established licensing procedures shall be followed.
- Two-way radio communication systems equipment shall be compatible with existing systems operating in the area.
- Two-way radio communication shall be capable of being serviced and supported at the proposed facility, either by the manufacturer, manufacturer's representatives or authorized service agents or by Mobil personnel.

3.2. Paging System

A paging system shall be used to satisfy broadcast requirements within a facility.

3.2.1. Design

- The paging system design shall facilitate audible, intelligible communications into all parts of the facility.
- Design shall include provisions for both the ultimate facility layout and the projected ambient noise levels.
- Design consideration shall be given to potential noise pollution outside the facility.

3.2.2. Integration

Paging, intercom and alarm communications shall be integrated into a single system.

3.2.3. Reserve Power Capacity and Adjustable Speakers

Reserve power capacity and adjustable speakers shall be provided where ambient noise is unpredictable.

3.2.4. Environmental Noise Pollution Regulations

Environmental noise pollution regulations shall be reviewed. The applicability of these regulations shall be determined prior to design.

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3.2.5. Administrative Portion

The project engineer shall ensure that the administrative portion of this system is considered and provided.

3.3. Intercom System

An intercom system shall be used where members of a workforce converse frequently and at length with one another from fixed locations within the facility.

- The system shall be capable of both private and party line operation.
- The system design shall identify all intercom speakers and hand stations needed to satisfy operational requirements.
- Operations personnel shall be included in determining the placement of intercom stations.

3.4. Sound-Activated Telephone Systems

Sound-activated telephone systems shall be used where members of a workforce converse frequently and at length from fixed locations within the facility and where no other voice communications requirements exist.

3.5. Crane Communications

Where cranes are used at a marine facility, each crane cab shall be equipped with a radio to enable the operator to be in continuous contact with the supply vessels and personnel on the deck.

- The equipment shall be located so that the operator may select channels while seated in the cab.
- Actuation of the transmit-receive operation shall be by foot switch, control handle switch or voice-actuated.
- An external loudspeaker, with hand-held microphone and hand-operated transmit switch, shall be provided.
- The crane radio shall be capable of transmitting and receiving on the supply vessel's radio frequency. This can be accomplished by a separate radio or a control station for the platform radio.
- Due to cabling considerations between the cab and the fixed platform, a separate radio in the crane cab is preferred. Refer to MP 41-P-72.

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3.6. Construction Site Communications

The vendor shall ensure that adequate voice communications systems are provided for all parties involved in the project construction, pre-commissioning and startup. The infrastructure to support special operational circumstances, such as drilling operations and plant turnaround, shall be provided.

4. Communications Systems–Onshore

4.1. General

Communications systems shall be provided by the contractor.

4.1.1. Existing Systems

At existing plants this may only require an addition to, or extension of, the existing communications systems, provided that the existing systems have capacity, facilities for expansion and are performing satisfactorily.

4.1.2. New Systems

New systems normally are installed at new sites and at existing sites where large independent process units will be installed or where spare capacity or quality performance of a communications system is lacking.

4.1.3. Types and Specific Requirements

- Because communication systems are not usually defined early in the design phase of a project, it shall be the responsibility of the contractor to confer with Mobil to establish the requirements of communication systems to be installed.
- Plant preferences and the types of plant operation and maintenance procedures shall determine communication system needs.

4.1.4. Overseas Networks and Connections

Where connection with the Mobil Automatic Telephone System or an overseas network is required, proposed plant communications systems shall be coordinated with the Mobil Telecommunications Department.

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4.2. Telephone Systems

Telephone systems shall use private exchange equipment or communications key equipment as requirements dictate.

Equipment from independent telephone companies or manufacturers shall comply with the requirements and specifications of the local or national body regulating communications matters and governing their implementation and use.

4.2.1. Switchboards

- Manually operated switchboards shall be combined with automatic systems to handle incoming and outgoing calls, as applicable.
- A minimum of five trunk lines shall be provided between the switchboard and outside exchange for each hundred plant numbers or switchboard positions. This requirement is in addition to lines required for private telephones, fax facilities or other exclusively-used lines between Mobil facilities.
- Switchboards shall be located in administration or main office buildings and housed in compliance with local building, safety and security codes.
- Telephone systems shall be arranged to enable incoming and outgoing calls to be transferred to the main gatehouse or other specified location when the manual switchboard is unattended.

4.2.2. Locations

Telephones shall be installed in:

- Offices
- Control rooms
- Laboratories
- Guardhouses
- Shops
- Warehouses
- Utility areas
- Major electrical equipment rooms and buildings

Telephones shall conform with area classification requirements.

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4.2.3. Equipment/Spares

- Main and branch telephone cables that are to be owned and maintained by Mobil shall contain approximately 25 percent spare pairs.
- Specific circuitry and equipment necessary for interrelated fire alarm systems, paging systems or other communications systems shall be provided as part of the telephone system.

4.3. Radio Paging Systems

Radio paging systems shall be arranged to transmit a coded tone alert for both selective and group paging and a subsequent voice message to the person or group being paged.

- Each radio paging system shall be arranged for manual operation from a central location and for dial-interconnection with the plant telephone system to allow selective paging from all telephones.
- An adjustable time period of approximately 10–60 seconds shall be provided for transmission of the voice message. This feature limits the time of an in-service call and enables more receivers to be handled on a single system.
- Paging formats with numeric or alpha-numeric display messages increase the capacity of a paging system by reducing the time required for transmission of the message.
- Numeric or alphanumeric display page messaging shall be interfaced with process systems to annunciate alarms and messages directly to pagers and CRT screens.
- Priority telephones shall be provided at a central location and other assigned locations to allow manual takeover of the paging system for emergency reasons.

4.4. Radio Communications Systems

Radio communications systems shall provide two-way communication between individuals, vehicles and fixed stations as required.

4.4.1. Licensing

Licenses that permit radio communications system usage at assigned frequencies shall be obtained from the regulatory authority. No equipment shall be placed in operation until full compliance has been assured. The FCC requires completion of construction within one year of the issuance of a license.

4.4.2. FM Communication Systems

Frequency-modulated communications systems operating in the 450, 800 or 900 MHz bands are preferred for refineries and continuous process chemical plants. These systems provide the best system configurations, with superior

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radio signal coverage over process and utility areas, as well as the best suppression of electrical system noise.

4.4.2.1. 800 and 900 MHz Communications Systems

The 800 and 900 MHz radio communications systems are configured as either conventional systems (similar to 450 MHz systems) or as trunked radio systems. Trunked radio systems may include 450 MHz to 470 MHz in the future. The 800 and 900 MHz systems, where frequencies are available, provide exclusive use of the radio frequency to the licensee as long as FCC loading criteria are met for portable and mobile units.

4.4.2.1.1. Trunked Communications Systems

Trunked radio systems use a computerized central controller that distributes the communications load dynamically over the channels available to the system. In this way a large number of personnel can use a limited number of communication paths because of the power of the central controller.

4.4.2.1.2. Loading Criteria

The loading criteria for the 800 and 900 MHz systems are 100 units per frequency. Seventy percent of the loading requirements shall be met within five years from the licensee grant date in order to maintain exclusive use of the frequency resource. Trunked radio systems can be put in service under an FCC provision for a five-year slow growth implementation. Portable and mobile loading can be scheduled over the five-year plan and shall be loaded as reflected in the slow growth declaration.

4.4.3. 150–160 MHz Communication Systems

Radio communication systems operating in the 150–160 MHz band may be installed at locations where the type of plant installation, system usage and vendor performance tests indicate such systems shall perform satisfactorily.

Conventional systems for plantwide communication shall be independent of systems installed for process communication.

4.4.4. Repeater-Type Communication Systems

Repeater-type communications systems that allow unrestricted two-way communication are preferred, especially for process and utilities control. These systems allow the use of low-powered, lightweight, limited-coverage portable transceivers that are approved for classified areas. The portable transceivers transmit to the repeater station, which in turn retransmits to all mobile and portable transceivers. Because the repeater station has higher power, wider coverage can be achieved.

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4.4.5. System Base Station Requirements

- Each base station shall be provided with a high-gain antenna mounted at an elevated location. The antenna location and base station power level shall be reviewed in regard to their effect on sensitive process instrumentation.
- Base stations shall be located in blast-resistant buildings, where available, or in other buildings that are unlikely to be damaged by a major fire or explosion. The locations shall also be suitable for use as command points during emergencies.
- A reliable alternate power source, used as a standby for the normal power source, shall be provided for each base station.
- Equipment redundancy shall be reviewed on an individual basis.
- For trunked systems in critical service, serious consideration shall be given to providing a redundant trunked system with switchover capability. A trunked system can be made to operate as a conventional system through individual repeater assignments (fail safe mode) upon central controller failure. This system configuration is allowed by the FCC (US) on an emergency basis.

4.4.6. Field Transceiver Requirements

- Permanently installed mobile transceivers for maintenance and emergency radio communication shall be installed in selected plant vehicles, such as fire trucks and ambulances. The power level selected for these transceivers shall be reviewed in regard to a range of vehicle travel and effect on sensitive process instrumentation. The vehicles shall also be provided with antennas and battery-operated portable transceivers.
- Battery-operated portable transceivers shall be carried by designated personnel.
- Sufficient extra sets of rechargeable batteries shall be provided to enable the batteries used in portable transceivers by prior shift personnel to be recharged in the succeeding eight-hour period.
- Battery chargers with sufficient positions and capacity to charge all assigned transceiver batteries in an eight-hour period shall be provided.
- Sufficient spare portable transceivers shall be provided to replace units that might be out of service for maintenance or repair.
- Where applicable, portable transceivers, portable microphones and portable headsets shall be suitable for the area classification requirements.

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4.4.7. Control Room

Desk sets for use in maintenance and emergency communications systems shall be provided at designated locations. These sets shall be directly wired to the system control console.

Speakers and panel handsets, directly wired to the control console, shall be provided in control rooms for process and utilities control. A message from a portable or mobile field transceiver shall be initially received through the control room speakers and, at the discretion of the operator, be muted when communication has been established via the handset and field transceiver. The control room speakers shall be muted when an operator transmits through a panel handset.

4.4.8. Emergency Provisions

Systems shall have provisions for manual takeover during emergencies.

4.5. Special-Purpose Transmitter Systems

4.5.1. Uses

Special-purpose transmitter systems may be used for status signals or alarms where hard-wired systems are not practical. Such uses might include:

- Alarms for pipeline equipment
- Alarms for offshore equipment
- Oil-film detection equipment

4.5.2. Frequencies

- Frequencies selected for special-purpose transmitter systems shall not create interference with other in-plant or out-of-plant communications systems. The equipment shall not be affected by other types of transmitters in the area.
- Transmitters and receivers shall be approved for the areas in which they shall operate.

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5. Data Communications Systems

5.1. Applications Supported

Data communications systems support numerous applications such as:

- Facility alarm and protective systems
- Programmable Logic Controllers (PLC)
- Computers
- Local area networks
- Remote Terminal Units (RTU) and instruments

5.2. Protocols

Where practical, these systems shall use high-level industry standard protocols and readily available hardware. Some proprietary protocols (Modbus, for example) may still be appropriate.

5.3. Compatibility

- All data communications systems shall be verified for end-to-end compatibility.
- Selected data communications schemes and hardware shall be consistent and compatible with the existing data communications environment in the operating unit. Mobil shall coordinate compatibility requirements.

5.4. Bandwidth

- Data communications systems shall include sufficient spare bandwidth to support planned and anticipated growth.
- Mobil shall specify in detail the amount of initial spare bandwidth that shall be provided.

5.5. Physical Limitations

The physical limitations of various data communications standards, for example, RS232, V.35, T1 facility side, shall be followed.

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5.6. Instrument Loops

Instrument loops are not within the scope of this MEP.

6. Alarm Communication System–Offshore

6.1. General

Alarm communications systems shall be used when required to enhance personnel safety or where required by local regulations. Alarm communications systems can be audible and/or visual. Offshore U.S. alarm and communication systems shall comply with 33 CFR 140, Subchapter N, Subpart B.

6.2. Design

Alarm communications systems shall be of modular design, with each station (visual and/or audible) capable of operating independently to provide maximum reliability and ease of expansion.

6.3. Number and Location

The number and location of alarm stations shall ensure that the entire facility has adequate audible and visual alarm coverage.

6.4. Signals

- The alarm signal shall be audible over normal operating noise level generated by other equipment.
- Visual alarm signals shall be strategically located, to provide maximum visibility from different directions.

6.5. Manual Alarm Initiation

Where required, each alarm station shall be capable of manual alarm initiation. U.S. offshore facilities are required to have the following alarm initiation capabilities:

- Abandon platform
- Fire

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- Process emergency

6.6. Priority

The latest applicable regulations and input from both Mobil Loss Prevention and Mobil operations shall be included to determine the priority and importance of these alarms.

6.7. Reset (Silence) Buttons

Reset (silence) buttons shall be located at appropriate points in the facility and at the main control panel.

6.8. Interfacing

The alarm communications system shall be designed to be an integral part of the facility overall safety systems. Consequently, it shall be required to interface with other safety systems, such as:

- Fire and gas monitoring devices
- Fire control equipment such as fire pumps, CO_2 releases
- Protective/emergency shutdown systems using relay logic or PLCs
- Pressurization systems
- Public address systems

7. Alarm Communication System–Onshore

7.1. Design Criteria

Normally, electrical system alarm panels shall be located in electrical equipment buildings, at main substations, unit substations and at major electrical equipment buildings associated with process units or operating areas.

- Electrical system alarm panels shall be provided with a backup power supply in order to provide effective monitoring during system disturbances and outages.
- Alarm annunciation shall be sounded where operation personnel are continuously in attendance.

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7.2. Acknowledgement

- Acknowledgment of the alarm at the control room shall not affect the alarm condition at the substation or electrical equipment building. Investigation at the local electrical system alarm panel shall be necessary to determine the specific alarm condition and to silence the local audible signal. Normally, the audible signal at the local alarm panel shall be located outdoors.
- Acknowledgment of an alarm condition at a local electrical system alarm panel shall not prevent subsequent local alarm conditions in the electrical system from reactivating the control room monitor alarm.

7.3. Equipment Requirements

- The location at which the monitoring alarm is initiated shall be included in the nameplate description.
- Alarms for electrical system alarm panels shall be audiovisual. Alarm panels shall have, as a minimum, illuminated nameplates or lights with identifying nameplates. Alarms shall be grouped in a single alarm panel or cabinet. Each panel or cabinet shall be provided with alarm, test and acknowledge pushbuttons. Alarm panels can be the LED display type.
- Alarms shall be designed to operate from either a normally open or normally closed field contact. Unless otherwise required by the installation, alarm conditions shall be initiated by the opening of a field contact. The alarm circuits shall be connected to be self-checking and fail-safe, where applicable.
- Alarm equipment, including the initiating switches, shall be provided with enclosures suitable for the area classification requirements.
- Alarm equipment for monitoring electrical system installations shall be compatible and interchangeable with the alarm equipment described in MP 32-P-07.

7.4. Alarm Conditions

A single common alarm designated Electrical System Malfunction shall be provided to monitor each electrical system alarm panel. These monitoring alarms shall be located in the central control room when this control concept is used for multiple process units or operating areas. If the central control room concept is not used, the monitoring alarm shall be located in the control room associated with that unit or area.

Common equipment alarms shall be used to obtain the alarms required.

Alarm systems shall indicate the following.

- A change in the normal operating position of the incoming, bus-tie and feeder circuit breakers at main substations.

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- A change in normal operating position of incoming and bus-tie circuit breakers having secondary-selective controls at medium-voltage (2.4 to 15kV) unit substations. Alarming of the feeder circuit breakers is not required, except for special circumstances or where the load being supplied is remote from the substation.
- A change in normal operating position of incoming and bus-tie circuit breakers having secondary-selective controls at low-voltage (under 600 V) unit substations. Alarming of feeder circuit breakers is not normally required.
- A ground condition occurring on the normally ungrounded medium- and low-voltage distribution buses.
- A ground condition on battery-supplied direct current (DC) systems for switchgear controls and critical interlock services, as a minimum.
- A loss of alternating current (AC) supply to battery chargers for the systems noted above.
- A loss of charging current to batteries.
- A low voltage on DC systems derived from batteries. Alarms shall be actuated at approximately 85 percent of normal voltage.
- A loss of pressurization or the transfer of blowers in pressurizing systems for buildings.
- When the RUN-STOP selector switch (for blowers in building pressurizing systems) is placed in the STOP position.
- When the standby generator is started.
- An abnormal condition of insulating medium in main substation power transformers (high liquid temperature, low gas pressure).
- The loss of specific equipment and circuitry necessary to ensure personal safety and security.
- An abnormal condition in the uninterruptible power supply (UPS), including loss of the alternate power source.

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Pressure Relief and Vapor Depressuring Systems

MP 70-P-06

July 1998

Scope

This Mobil Engineering Practice (MEP) provides guidance on the selection and design requirements for pressure relief and vapor depressuring systems. It also provides guidance for alternative overpressure protection including High Integrity Process Shutdown (HIPS) systems.

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Table of Contents

Scope **1**

Table of Figures **6**

1. References **7**

1.1. MEPS–Mobil Engineering Practices 7

1.2. Mobil Data Sheets 7

1.3. API–American Petroleum Institute 8

1.4. ASME–American Society of Mechanical Engineers 8

2. General **9**

3. Disposal Methods **9**

3.1. Vapor Discharge 9

3.2. Liquid Discharge 9

4. Disposal System Design Criteria for Vapor Discharge **10**

4.1. Direct Vapor Discharge to the Atmosphere 10

4.2. Vapor Discharge to a Closed Pressure Relief System 11

4.3. Vapor Discharge to a Lower Pressure Process System or Vessel 15

4.4. H_2S Relief 16

5. Disposal System Design Criteria for Liquid Discharge **16**

5.1. Liquid Discharge to an Onsite Liquid Knockout Drum 16

5.2. Liquid Discharge to a Lower Pressure Process System or Vessel 17

5.3. Liquid Discharge to an Oily-Water Sewer 18

5.4. Liquid Discharge to a Pump Suction 18

5.5. Cold Liquid Disposal 18

5.6. Thermal Relief 19

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6. Pressure Relief System Components 19

6.1. Pressure Relief Devices 19

6.2. Piping 26

6.3. Flare and Vent System Knockout Drums (Scrubbers) 28

6.4. Flashback Protection 30

6.5. Flare Stacks and Tips 32

6.6. Pilots and Ignitors 34

6.7. Combustion Assistance (Steam/Air) Systems 36

6.8. Alternative Flare Designs 38

6.9. Atmospheric Relief Vents 40

6.10. Vent Stacks 41

7. Vapor Depressuring 41

7.1. General 41

7.2. Depressuring Flowrate 42

7.3. Depressuring Valves 42

7.4. Disposal of Discharge 43

7.5. Other Considerations 43

8. Alternate Means of Process Overpressure Protection 44

8.1. HIPS Prerequisites 44

8.2. Consequences of Failure 45

8.3. Independent Function 45

8.4. Fail-Safe Design 45

8.5. Response Time 45

8.6. Surge Pressures 46

8.7. Bypasses 46

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9. Disposal System Design Review 46

9.1. New Installations 46

9.2. Existing Installations 46

9.3. Required Information and Documents 46

Appendix A: Load Analysis 53

1. Scope 53

2. General 53

2.1. Flare Load Design 53

2.2. Evaluation 53

2.3. Causes of Discharge 53

2.4. Factors Affecting Emergency Relief Load 53

2.5. Two-Phase Flow 54

3. Heat Input 54

3.1. Effect on System 54

3.2. Methods 54

3.3. Fired Heaters 55

3.4. Heat Exchangers 55

3.5. Reactor Systems 56

3.6. Compressors 57

3.7. High-Pressure Ethylene Systems 57

4. Heat Removal 57

4.1. Basic Methods 57

4.2. Air and Water Exchangers 58

4.3. Heat Exchangers 59

5. Heat Content of System 59

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5.1. Analysis 59

5.2. Vapor Removal 60

Appendix B: Protection of Catalyst-Filled Reactors 61

1. 1. General 61

2. 2. Flow Resistance 61

3. 3. Special Pressure Relief Devices 61

Appendix C: Dynamic Pressure Relief System Analysis 63

Appendix D: Flare Sizing Calculations 64

1. 1. Flare Stack Height 64

2. 2. Flare Tip 65

Table of Figures

Figure 1: Pressure Relief System–Pressure Relief Valves, Leads, Laterals, Headers and Purge Gas System 12

Figure 2: Knockout Drum (Scrubber) Level Control and Liquid Disposal 13

Figure 3: Closed Pressure Relief System Using Combination Igniter/Pilot 14

Figure 4: Closed Pressure Relief System Using Flame-Front Generator 15

Table 1: Examples of Block Valves with Pressure Relief Valves to Permit Removal of Pressure Relief Valves for Maintenance or Testing 25

Figure 5: Water Seal Drum 32

Table 2: Allowable Radiant Heat Intensities in W/m^2 ($Btu/hr/ft^2$) Excluding Solar Radiation 33

Figure 6: Dispersant Chart for Smokeless Flaring 37

Figure 7: Staged Multi-Tip Flare 38

Table 3: Proprietary Flares 39

Figure 8: Typical Relief and Depressuring Load Summary–SI (Metric) Units 48

Figure 9: Typical Relief and Depressuring Load Summary–Customary Units 49

Figure 10: Closed Pressure Relief System and Flare–Typical Single-Line Diagram–SI (Metric) Units 51

Figure 11: Closed Pressure Relief System and Flare–Typical Single-Line Diagram–Customary Units 52

Table D–1: Allowable Radiant Heat Intensities in W/M^2 ($Btu/Hr/Ft^2$) Excluding Solar Radiation 65

Figure D–1: Installation of an Operating Flare and an Emergency Flare 66

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1. References

The following publications form a part of this Practice. Unless otherwise specified herein, use the latest edition.

1.1. MEPS–Mobil Engineering Practices

MP 12-P-01	Pressure Vessels-Design & Fabrication
MP 16-P-01	Piping-General Design
MP 32-P-04	Control Valves and Actuators
MP 32-P-07	Safety Interlock Systems and Alarms
MP 32-P-08	Control Centers
MP 34-P-10	Thermal Insulation - Hot Service
MP 70-P-01	Loss Prevention - Facilities
MP 70-P-05	Fireproofing

1.2. Mobil Data Sheets

Mobil Data Sheets	Mobil Data Sheet Home Page
T7006C01	Pressure Relief & Vapor Depressurizing Systems - Pressure Relief Valves - Customary Units
T7006M01	Pressure Relief & Vapor Depressurizing Systems - Pressure Relief Valves - Metric Units
T7006C02	Pressure Relief & Vapor Depressurizing Systems - Rupture Disks - Customary Units
T7006M02	Pressure Relief & Vapor Depressurizing Systems - Rupture Disks - Metric Units
T7006C03	Pressure Relief & Vapor Depressurizing Systems - Tank Vents & Breathers - Customary Units
T7006M03	Pressure Relief & Vapor Depressurizing Systems - Tank Vents & Breathers - Metric Units
T7006C04	Pressure Relief & Vapor Depressurizing Systems - Building Design Data - Customary Units
T7006M04	Pressure Relief & Vapor Depressurizing Systems - Building Design Data -

	Metric Units
D7006C01	Pressure Relief & Vapor Depressurizing Systems - Documentation Requirements Sheet
I7006C01	Pressure Relief & Vapor Depressurizing Systems - Inspection & Testing Requirements Sheet

1.3. API–American Petroleum Institute

API PUBL 931	Manual on Disposal of Refinery Wastes, Volume on Atmospheric Emissions, Chapter 15 — Flares
API RP 520 PT I	Sizing, Selection, and Installation of Pressure-Relieving Devices in Refineries Part I - Sizing and Selection Sixth Edition; Errata - 1994
API RP 520 PT II	Sizing, Selection, and Installation of Pressure-Relieving Devices in Refineries Part II - Installation Fourth Edition
API RP 521	Guide for Pressure-Relieving and Depressuring Systems Fourth Edition
API STD 526	Flanged Steel Pressure Relief Valves Fourth Edition
API STD 527	Seat Tightness of Pressure Relief Valves Third Edition (R 1996)
API STD 620	Design and Construction of Large, Welded, Low-Pressure Storage Tanks Ninth Edition; Addendum 1-1996; Additional Pages for Addendum 1-1997
API STD 2000	Venting Atmospheric and Low-Pressure Storage Tanks Nonrefrigerated and Refrigerated Fourth Edition

NOTE: API PUBL 931 has been withdrawn and is no longer available from the API. However, Mobil considers the referenced material to be valid for Mobil's purposes except as may be noted in this Practice.

1.4. ASME–American Society of Mechanical Engineers

ASME B31.3	Process Piping
ASME B31.4	Liquid Transportation Systems for Hydrocarbons, Liquid Petroleum Gas, Anhydrous Ammonia, and Alcohols
ASME SEC I	BPVC SECTION I Rules for Construction of Power Boilers Addenda - 1995; Addenda - 1996; Interfiled (Boiler and Pressure Vessel Codes)
ASME SEC VIII D1 AB	PVC SECTION VIII Rules for Construction of Pressure Vessels DIVISION 1 - SUBSECTION A - General Requirements (Boiler and Pressure Vessel Codes)
ASME SEC VIII D1 BB	PVC SECTION VIII Rules for Construction of Pressure Vessels DIVISION 1 - SUBSECTION B - Requirements Pertaining to Methods of Fabrication

	of Pressure Vessels (Boiler and Pressure Vessel Codes)

2. General

The selection and design requirements for pressure relief and vapor depressuring systems and alternative overpressure protection including High Integrity Process Shutdown (HIPS) systems shall be in accordance with requirements of this MEP, unless superceded by more stringent local regulations.

This Practice defines the basic requirements for pressure relief and vapor depressuring systems. It also provides design guidance for High Integrity Process Shutdown (HIPS) systems that may be provided in lieu of pressure relief systems in certain situations.

This Practice does not cover systems for relieving explosion overpressure from buildings and other enclosures. Disposal of toxic materials may require special design considerations and are outside the scope of this MEP. Guidance shall be sought from a specialist for these situations.

3. Disposal Methods

3.1. Vapor Discharge

Vapor and gas discharges can be disposed of as follows:

1. To the atmosphere, either individually or through a closed pressure relief system terminating at a vent stack
2. To a closed pressure relief system and flare
3. To a lower pressure process vessel or system

Vapor depressuring valves shall discharge only to a closed pressure relief system.

3.2. Liquid Discharge

Liquid discharges can be disposed of as follows:

1. To an onsite liquid knockout drum
2. To a lower pressure process vessel, system or storage tankTo oily-water sewers (only if the material will not flash or cause flashing of other materials in the sewer)

3. To a pump suction (if the pump will not overheat or can withstand the expected temperature rise), preferably to the vessel that supplies the pump suction
4. To a burn pit or other liquid disposal facility
5. For pipelines and piping systems, directly to the atmosphere in accordance with ASME B31.3

Liquids shall not discharge directly into a vapor disposal system.

3.2.1. Emergency Liquid Relief Facilities

Emergency liquid relief facilities shall be installed as follows:

1. Liquid from desalter relief valves shall discharge to the crude tower flash zone.
2. Liquid from relief valves on liquid-filled vessels in gas plants and product treating plants shall discharge to an onsite liquid knockout drum that vents vapor to the closed pressure relief system.

4. Disposal System Design Criteria for Vapor Discharge

4.1. Direct Vapor Discharge to the Atmosphere

Discharges to the atmosphere shall be in the vapor state and shall be below their auto-ignition temperature. The discharges shall also meet all applicable air quality control requirements and at least one of the following physical property requirements:

- Flammable vapors are lighter than air.
- Flammable vapors are equal to or heavier than air, molecular weight is less than 80 and minimum velocity at discharge is 152 m/s (500 ft/s) based on the maximum capacity of the relief valve. Maximum velocity shall not exceed 80 percent of sonic velocity (see Appendix D, Section 2 of this MEP).
- Flammable vapors have a molecular weight greater than 80. Velocity at discharge is as specified in the previous paragraph. A vapor dispersion analysis shall be conducted to verify that ground level vapor concentrations do not pose a flammability or health hazard.
- Vapors, of any molecular weight, are nonflammable, nontoxic, noncondensable and noncorrosive.

A typical direct atmospheric discharge relief system shall include the following components:

1. One or more pressure relief devices; see Section 6.1 of this MEP.
2. Discharge piping (tailpipe); see Section 6.2 of this MEP.

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4.2. Vapor Discharge to a Closed Pressure Relief System

Where discharge of vapor to the atmosphere or to a lower pressure system is not permissible or practical, vapor shall discharge to a closed pressure relief system that terminates in a flare. Vapors from volatile liquids and non-condensable gases shall also discharge to a closed pressure relief system. The design of the closed pressure relief system shall meet applicable air quality requirements and combustion products shall be released at a safe location. Continuously burning pilots are recommended to ensure the combustion of all gas and vapors.

Discharge of vapors into a closed system terminating in a vent stack, which releases the vapors to the atmosphere, is acceptable when allowed by regulations.

4.2.1. Special Considerations

Special considerations are necessary when closed pressure relief systems are required to handle either extremely hot, cold or heavy vapors or reactive chemicals such as pyrophoric or corrosive materials.

4.2.2. Pressure Relief Discharges

Pressure relief discharges to a flare shall not exceed 6 percent oxygen by volume. When a system may exceed 6 percent oxygen, such as during a unit regeneration, pressure relief valves that normally discharge into a closed pressure relief system shall be arranged so that the discharge can be readily diverted to a combuster that is designed to handle oxygen-rich hydrocarbon mixtures within the flammable range.

4.2.3. Typical Closed System

A typical closed pressure relief system (see Figures 1–4) shall include the following components:

1. Pressure relief devices; see Section 6.1 of this MEP.
2. Disposal piping (leads, laterals, unit and main headers); see Section 6.2 of this MEP.
3. Knockout drums (scrubbers) for accumulation and removal of liquids that have condensed or settled out; see Section 6.3 of this MEP.
4. Seals or purge gas or both, for flashback protection; see Section 6.4 of this MEP.
5. Flare stacks and tips or a vent stack; see Section 6.5 or 6.10 of this MEP.
6. Igniter(s) and pilots (for flare only); see Section 6.6 of this MEP.

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7. Steam or air for smokeless burning (for flare only); see Section 6.7 of this MEP.

8. Figure-eight blinds and gate valves located in unit headers near battery limits, with suitable platforms, to safely isolate the unit pressure relief system when units are shut down; see Figure 1.

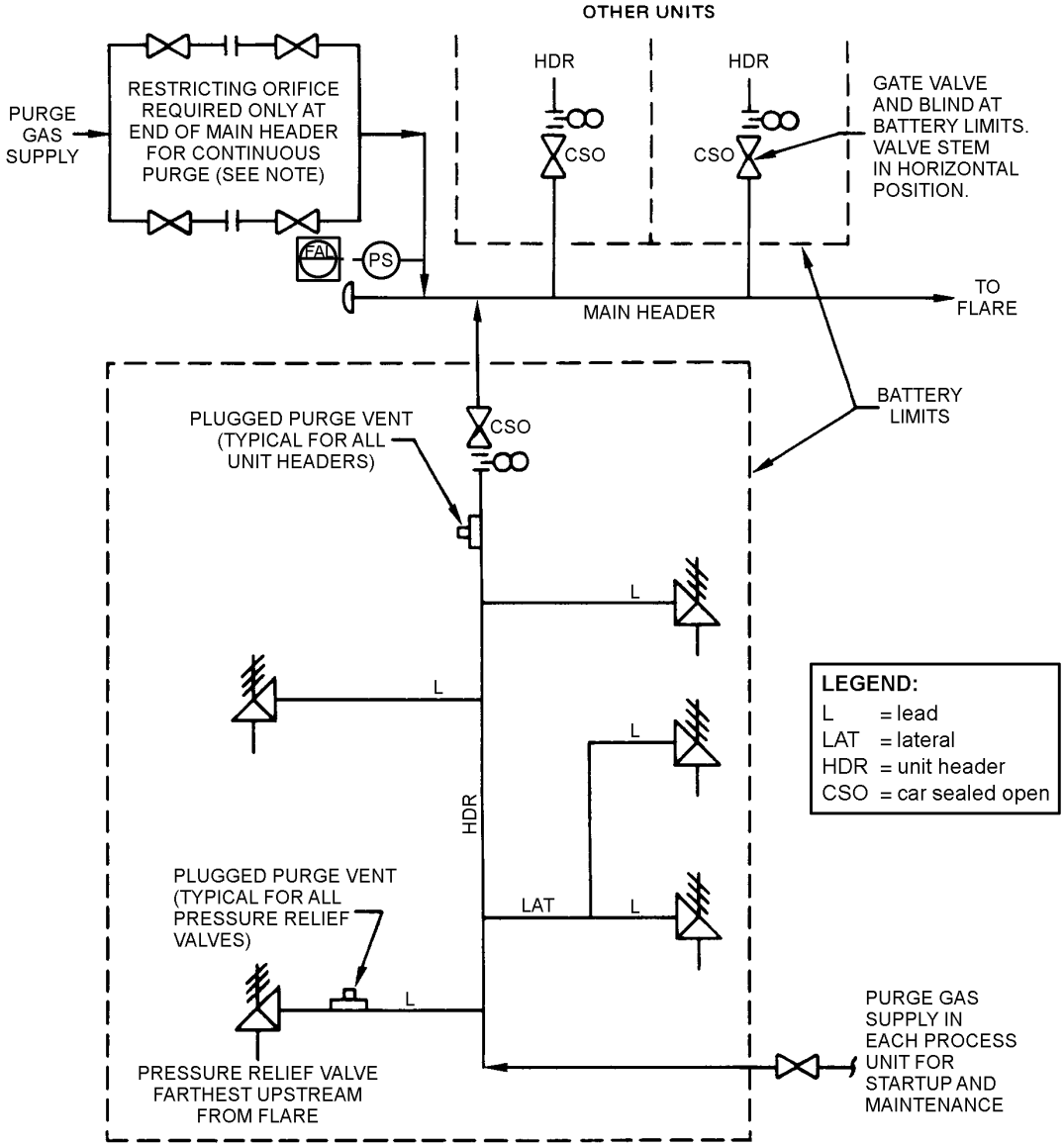

Figure 1: Pressure Relief System–Pressure Relief Valves, Leads, Laterals, Headers and Purge Gas System

NOTES:

1. After startup, purge gas shall be injected into end of main header on a continuous basis.

2. This figure is schematic.

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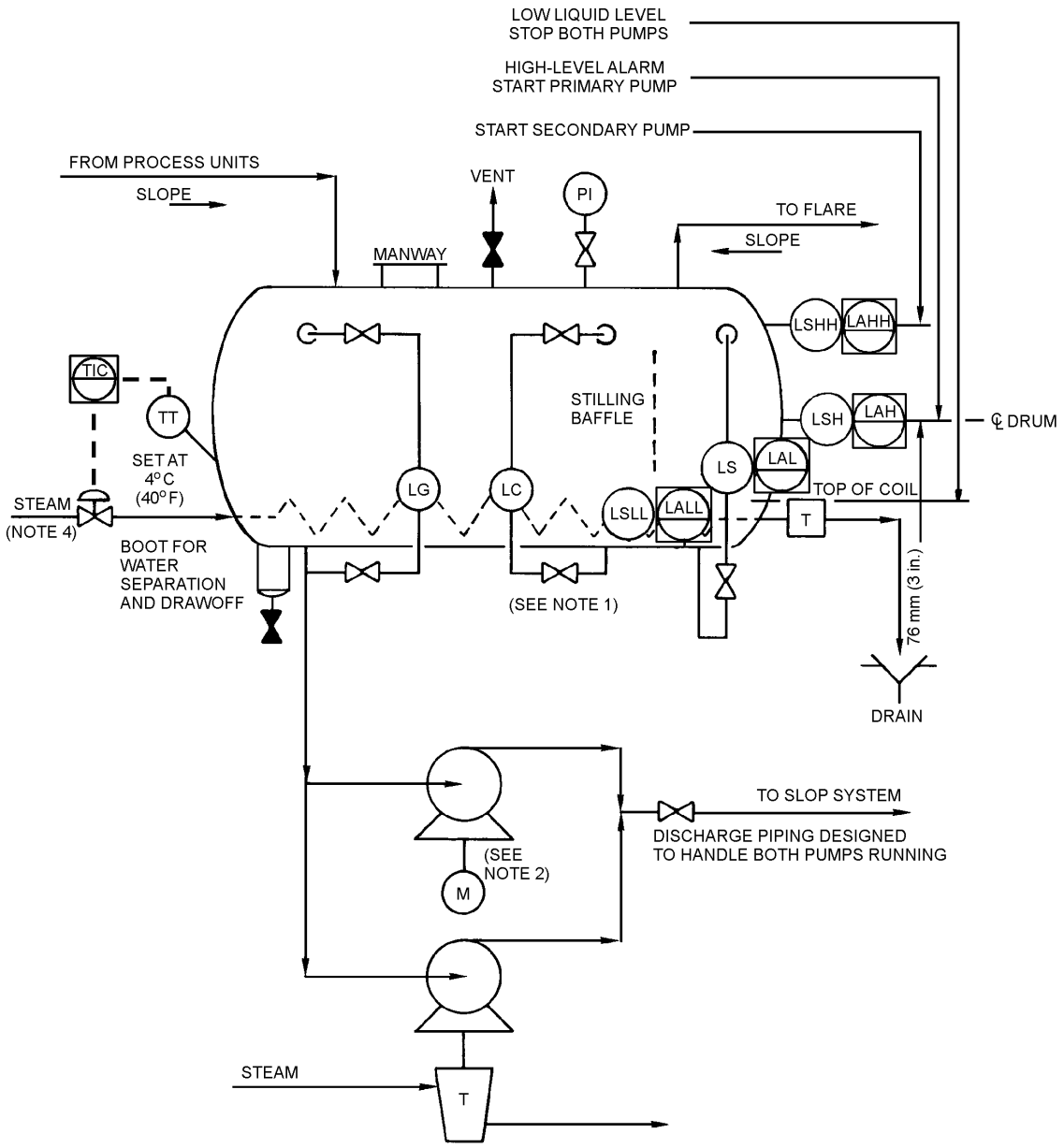

Figure 2: Knockout Drum (Scrubber) Level Control and Liquid Disposal

NOTES:

1. Instrument so that either pump can be operated as a primary or secondary pump.
2. Reciprocating pumps may be used as alternates.
3. This figure is schematic.
4. Heat may be provided by electric tracing or an alternate heating medium if steam is not available.

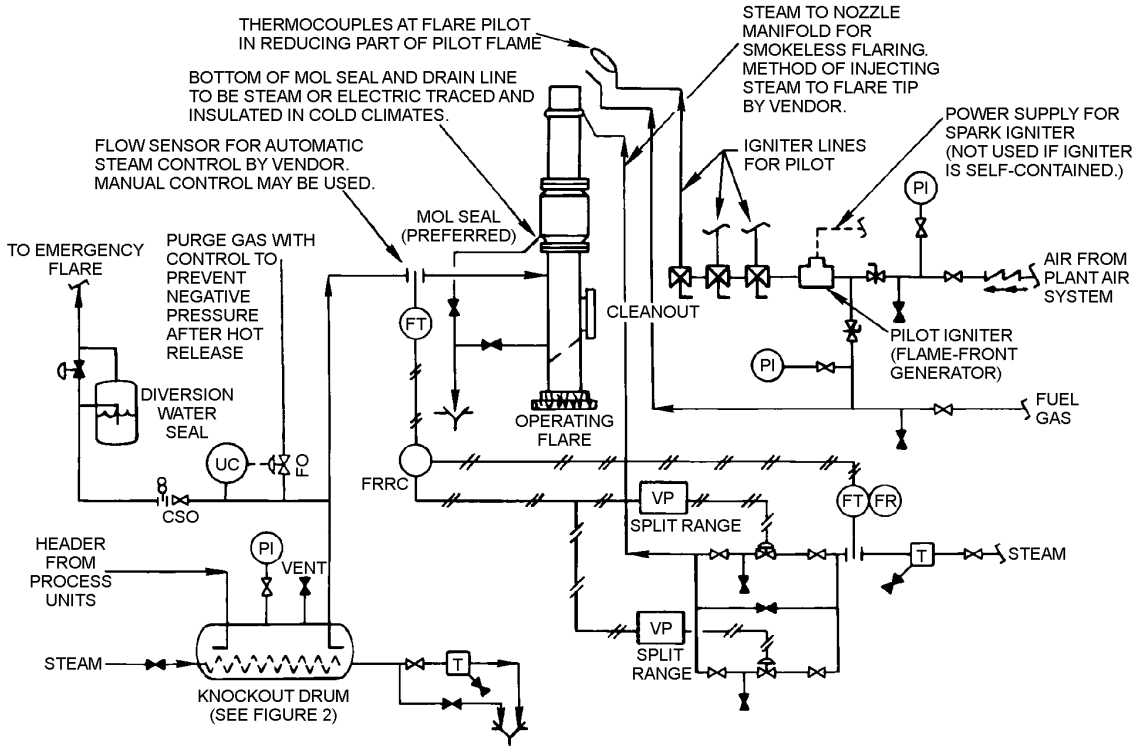

Figure 3: Closed Pressure Relief System Using Combination Igniter/Pilot

NOTE: This figure is schematic.

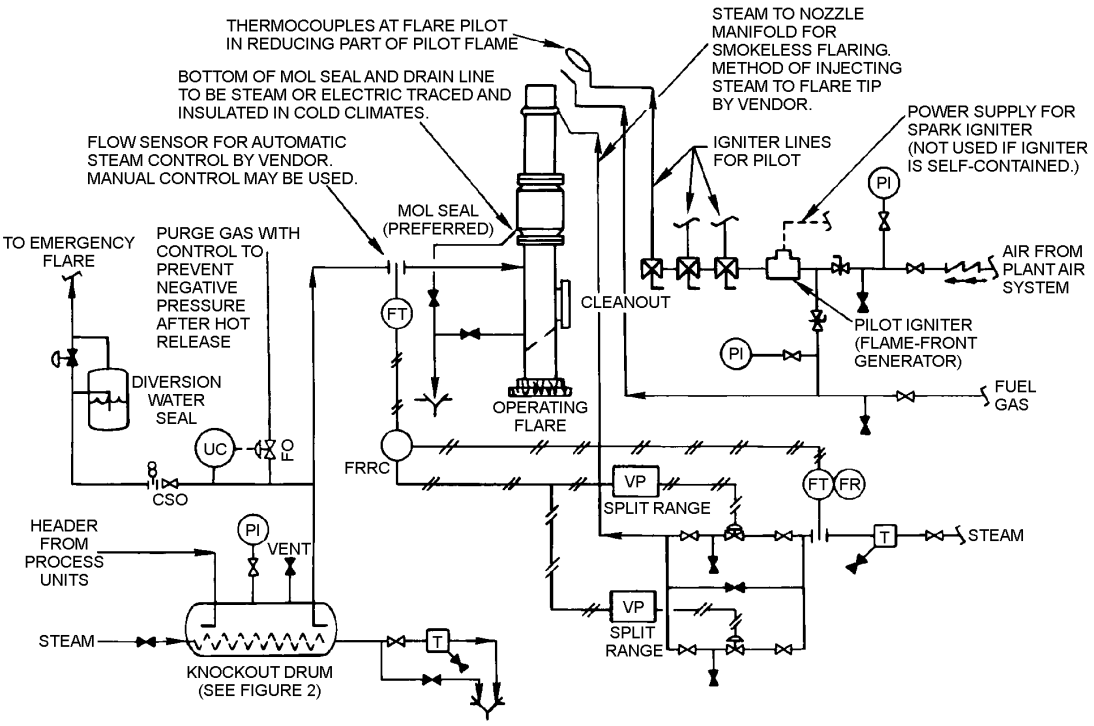

Figure 4: Closed Pressure Relief System Using Flame-Front Generator

NOTE: This figure is schematic.

4.3. Vapor Discharge to a Lower Pressure Process System or Vessel

1. Individual pressure relief valves may discharge to a lower pressure process system or to a vessel capable of handling the discharge. Although this type of disposal system is infrequently used for pressure relief in the vapor state, it is recommended for discharges that contain corrosive materials (which may damage a closed pressure relief system) or for materials that shall be recovered. Care shall be taken to ensure that a high-velocity stream from a pressure relief valve does not impinge on internal vessel fittings or displace trays or other internal equipment.

2. Pressure relief valves that discharge vapors to a lower pressure process system or to a vessel may require a design with high backpressure. The backpressure is determined by adding the lower-pressure-system relief pressure and the pressure drop in the piping from the pressure relief valve to the lower pressure system. Pressure relief valves that discharge to a lower pressure system shall meet the requirements of Section 6.1 of this MEP.

3. Recovery of vapors to the fuel system in non-emergency situations shall be considered.

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4. A typical vapor discharge system to a lower pressure process system or vessel shall include the following components:

   a) Pressure relief devices (see Section 6.1 of this MEP)

   b) Discharge piping to the lower pressure system or vessel (see Section 6.2 of this MEP)

4.4. H_2S Relief

Pressure relief for H_2S bearing streams from sulfur recovery units (SRUs) and other sources shall be discharged to either a dedicated "acid gas" flare or a common flare with hydrocarbons, as described below.

H_2S disposal facilities that use a dedicated flare shall be arranged as follows:

- Facilities shall be provided to inject a hydrocarbon gas stream, such as fuel gas, into the flare header to ensure the minimum required heating value for the flare is met. The hydrocarbon gas shall be automatically added in any upset conditions that are likely to send the ammonia/acid gas stream to the disposal system. (Refer to ASME B31.4.)
- A forced air pilot ignitor system shall be provided to handle all regenerator and ammonia acid gas streams. The stack can be adjacent to a hydrocarbon flare stack and supported within the hydrocarbon stack support structure. This minimizes acid corrosion and improves control of H_2S/NH_3 combustion.
- Steam shall not be added to the H_2S flare stack since that will reduce the combustion temperature and reduce H_2S combustion to SO_2/SO_3.
- Stack diameter shall be sized to keep gas exit velocity below 150 fps to avoid flame instability.

Where gas containing H_2S is discharged to a hydrocarbon flare, the metallurgy of the flare system piping, scrubber, flare stack, pilots, burners and other system components shall be suitable for exposure to the expected concentration of H_2S. The requirements for minimum heating value above shall also be met in this case.

5. Disposal System Design Criteria for Liquid Discharge

5.1. Liquid Discharge to an Onsite Liquid Knockout Drum

Onsite liquid knockout drums shall comply with Section 6.3 of this MEP and have an effective liquid reservoir that is sized to retain the required liquid relief discharge rate for the greater of the expected duration of the discharge or 15 minutes. A vapor discharge

line to the flare and a vapor space shall be provided to handle that portion of the liquid discharge that is expected to vaporize.

5.1.1. Pressure Relief Valves

Relief valves shall be designed to meet the requirements of Section 6.1 of this MEP.

5.1.2. Piping

Piping shall be designed to meet the requirements of Section 6.2 of this MEP.

5.1.3. Flashed Vapor Disposal from the Onsite Liquid Knockout Drum

The onsite drum shall be provided with a vapor line to a closed pressure relief system. The vapor line shall include a car sealed open block valve and a spectacle blind. The drum and piping shall be designed to withstand the maximum backpressure of the closed pressure relief system under maximum emergency relief conditions. The vapor space shall be designed to separate the liquid from the entrained vapor of the material that is discharged to the drum.

5.1.4. Liquid Disposal

Onsite liquid knockout drums shall be provided with a pump and a spare, each sized to empty a half-full drum within two hours (see Section 6.3 of this MEP). The pump shall discharge to a suitable slop line, slop tank or process vessel.

5.1.5. Critical Requirements

Onsite knockout drums shall be provided with a high-level alarm to alert the operator when liquid begins to accumulate in the drum so that remedial action can be taken. The pump(s) may be started manually or automatically by the drum level controller.

In addition, an independent high-high level alarm shall be provided, set to alarm at the design liquid capacity of the drum.

5.2. Liquid Discharge to a Lower Pressure Process System or Vessel

A lower pressure process system or vessel shall be capable of handling the required liquid relief discharge rate. Flashing at the lower pressure shall be taken into consideration.

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5.2.1. Pressure Relief Valves

Pressure relief valves shall comply with Section 6.1 of this MEP.

5.2.2. Piping

Piping shall comply with Section 6.2 of this MEP.

5.3. Liquid Discharge to an Oily-Water Sewer

Liquid discharge to an oily-water sewer shall be nonvolatile and nontoxic and shall be via a blowdown drum. The maximum liquid relief rate shall be within the oil removal capability of the oily-water treating system.

5.3.1. Pressure Relief Valves

Pressure relief valves shall comply with Section 6.1 of this MEP.

5.3.2. Piping

Piping shall comply with Section 6.2 of this MEP.

5.4. Liquid Discharge to a Pump Suction

Liquid relief shall discharge to the upstream liquid reservoir from which the pump takes suction.

5.4.1. Pressure Relief Valves

Pressure relief valves shall comply with Section 6.1 of this MEP.

5.4.2. Piping

Piping shall comply with Section 6.2 of this MEP.

5.5. Cold Liquid Disposal

Special precautions shall be taken to prevent freezing of relief system contents in pressure relief systems that are required to dispose of both cold and wet streams. Wherever practical, separate systems shall be provided for cold streams with segregation maintained until the streams become compatible. Except for LNG systems, cold liquid knock-out drums shall be provided with vaporization facilities.

Special precautions shall be taken to prevent low-temperature embrittlement of piping and equipment in pressure relief systems which are required to dispose of streams that enter the system at 20°F (-5°C) or colder.

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Special precautions shall be taken to prevent plugging of the relief system by other materials that freeze or become highly viscous at temperatures above 32°F (0°C).

5.6. Thermal Relief

Thermal relief valves shall discharge to a lower pressure system whenever possible. When this is not practical, they may discharge to an oily water sewer or to grade.

6. Pressure Relief System Components

6.1. Pressure Relief Devices

6.1.1. General

Pressure relief devices are required for all equipment subject to overpressure that results from outside pressure sources, external heat input or exothermic reactions.

Acceptable types of pressure relief devices include spring-loaded pressure relief valves, pilot-operated pressure relief valves, rupture disks and rupture pins.

6.1.2. Pressure Relief Valves

Pressure relief valves shall be designed and constructed in accordance with API STD 526 and API STD 527 and sized in accordance with API RP 520 PT I and API RP 521.

- Pressure relief valves shall be set in accordance with Section 6.1.7 of this MEP.
- For pressure relief valves in water and steam services, appropriate sections of the ASME Code shall apply. The ASME Code shall be the minimum acceptable where local codes do not cover relief valves or are less stringent.
- Weight-loaded pressure relief valves shall not be used without Mobil approval.
- Venting and breathing equipment for low-pressure, aboveground storage tanks at less than 103 kPa gauge (15 psig) shall be sized as specified by API STD 2000, Sections 1–3 or API STD 620, Section 6.

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6.1.2.1. Backpressure

Conventional pressure relief valves shall only be used when the built-up backpressure or the variable superimposed backpressure in the piping, downstream of the valve, is not expected to exceed 10 percent of the set pressure or 21 percent of the set pressure for ASME designed vessels under fire load conditions only.

Balanced pressure relief valves shall be used in vapor or gas service in which the built-up backpressure or the variable superimposed backpressure is expected to be between 10 percent and 50 percent of the set pressure. When backpressures are expected to exceed 30 percent of the set pressure, the valve manufacturer shall be consulted. The capacity of the valve and the maximum allowable backpressure on the bellows shall be verified with the manufacturer. Pilot operated relief valves shall be used when the built-up backpressure or the variable superimposed backpressure is expected to exceed 50 percent of the set pressure.

6.1.2.2. Operating Pressure

Operating pressures over 95 percent of the relief valve set pressure are not recommended. Vessels that operate between 90 and 95 percent of set pressure require pilot-operated pressure relief valves. Resilient seated valves may be considered only with Mobil approval.

6.1.2.3. Valve Types

All pressure relief valves shall be the manufacturer's standard type, recommended for specified services. These valves shall conform to the following ASME and API standards: ASME SEC VIII D1 AB; ASME SEC VIII D1 BB; API STD 526, for materials of construction and sizes of flanged valves; API STD 527, for seat tightness.

6.1.2.4. Sizing and Identification

Pressure relief devices shall be sized in accordance with API RP 520 PT I or local codes, whichever is more stringent. Each device shall be tagged with the Mobil valve number or other identification as specified on the purchase order. The data may be stamped on the nameplate or on a separate corrosion resistant tag that is permanently attached to the device.

Where required by local regulations, the pressure relief valve inlet and the mating flange of the protected equipment shall be die stamped with the Mobil tag number.

6.1.2.5. Materials

Construction materials of valves for sour gas service shall conform to NACE MR0175. For pressure relieving valves in unusually corrosive process conditions, body, bonnet and trim materials shall be approved by Mobil. An

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example of unusually corrosive process conditions is high-temperature production fluids containing high chloride levels in addition to acid gases.

6.1.2.6. Operating Temperatures

Pressure relief valves with Q, R and T size orifices shall not be used where the temperature exceeds 177°C (350°F) and the molecular weight is less than 10.

For special services, such as hydrogen service, pressure relief valves with soft seats or secondary O-rings may be used, subject to Mobil approval. Rubber materials such as Buna-N and Butyl may be used at temperatures below 93°C (200°F) and fluoroelastomers may be used at temperatures below 204°C (400°F).

6.1.2.7. Testing

1. Pressure relief valves shall be hydrostatically tested after assembly with a gag in place. The gag shall be removed prior to valve set pressure and leakage tests. The valve body shall be tested hydraulically or pneumatically, depending on the valve's service, as follows:

   a) The inlet side shall be tested at 1.5 times the specified set pressure for casting integrity.

   b) The outlet side shall be tested at 1.5 times the maximum allowable backpressure specified by the manufacturer for casting integrity.

   c) The outlet side shall be tested at a minimum pressure of 345 kPa gauge (50 psig) for soundness of mating parts.

2. Prior to field installation, all pressure relief valves shall be tested in the manufacturer's shop by qualified personnel for set pressure and seat leakage, using air, steam or water. Cold differential set pressures shall be stated on T7006C02 or T7006M02 (see the Mobil Data Sheets for this MEP) and shall be stamped on the nameplate in accordance with API STD 526.

3. Pressure relief valves shall not be gagged to permit hydrostatic testing of equipment or piping. Blinds shall be installed as required.

4. Pressure relief valves shall be furnished with extended spindles to allow testing in place.

6.1.2.8. Documentation

T7006C02 or T7006M02 (see the Mobil Data Sheets for this MEP) and relief device calculations prepared by contractors shall be submitted to and approved by Mobil prior to solicitation of quotes from supplier.

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6.1.2.9. Block Valves

- A spare pressure relief valve with appropriate block valves shall be installed:
  - In services where plugging, fouling or corrosion is likely to occur.
  - Where valve testing or maintenance is required between turnarounds.
- Pressure relief valve installations and relief valve installations with an upstream rupture disk which require maintenance and/or testing between turnarounds shall be provided with block valves arranged such as those shown in Table 1.
- Block valves used on the inlet or outlet of a pressure relief valve shall have full round port areas equal to or greater than, the inlet or outlet size of the pressure relief valve. Block valves shall be used only as permitted in the applicable codes. (See Section 6.1.9 of this MEP.)

6.1.3. Rupture Disks

Rupture disks shall not be used without prior Mobil approval. They shall comply with the requirements of API RP 520 PT I, ASME SEC VIII D1 AB and ASME SEC VIII D1 BB, Paragraph UG-127.

Only non-fragmenting rupture disks shall be used in series upstream of a pressure relief valve.

6.1.4. Rupture Pins

Rupture pins shall not be used without prior Mobil approval. They shall comply with the requirements of ASME SEC VIII D1 AB and ASME SEC VIII D1 BB, Paragraph UG-127-C. When installed upstream of a pressure relief valve, a "balanced" rupture pin assembly shall be used so that any pressure trapped between the rupture pin and the pressure relief valve will not affect the opening pressure of the rupture pin.

6.1.5. Pressure Relief Device Location

To prevent equipment overpressure, pressure relief devices shall be located in conformance with ASME SEC I, ASME SEC VIII D1 AB, ASME SEC VIII D1 BB, API RP 521 and API RP 520 PT II. Pressure relief devices shall be shown on P&I diagrams.

Pressure relief devices provided to discharge vapors shall be positioned to discharge from the vapor space or from the overhead vapor line of the protected vessel in order to minimize liquid entrainment.

Pilot sensing points for pilot operated pressure relief valves shall be at the pressure relief valve location. Remote sensing points may be considered only with Mobil approval. Pilot lines shall be sized to prevent blockage.

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On towers or vessels containing demister pads or packing, pressure relief devices shall be located so that dislodgment of the demister pad or packing will not obstruct the pressure relief device, or mechanical reinforcement shall be provided to prevent dislodgment.

6.1.6. Determination of Relief Loads

Pressure relief loads (see Appendix A) shall be calculated for each applicable failure in accordance with API RP 521 and API RP 520 PT I. See Appendix B of this Practice for catalyst-filled reactors. Calculations of pressure relief loads for process vessels under fire conditions shall be based on a minimum fire area of 280 m^2 (3000 ft^2) and a minimum height of 7.6 m (25 ft) above any level at which a fire may be located, in conformance with API RP 520 PT I and API RP 521.

6.1.7. Pressure Relief Valve Set Pressures

Set pressure requirements for pressure relief valves are as follows:

1. The pressure relief valve ambient set pressure, which initially shall be set in the supplier's shop, shall not exceed the maximum allowable vessel or equipment working pressure except as allowed in ASME SEC VIII D1 AB and ASME SEC VIII D1 BB.

2. The set pressure for a conventional pressure relief valve shall be corrected for any backpressure expected to exist before the valve opens. This shall be done by reducing the ambient set pressure by an amount equal to the constant backpressure present on the discharge side before the valve opens. This backpressure is limited to 10 percent of the set pressure before and after the valve opens (see API RP 521).

   For balanced and pilot-operated pressure relief valves the set pressure is not affected by the backpressure present before the valve opens. However, backpressure present after a valve opens affects the capacity of all types of pressure relief valves. Therefore, allowances shall be made in all capacity calculations (see API RP 520 PT I).

3. When the operating temperature exceeds 93°C (200°F), the ambient set pressure—determined in conformance with Section 6.1.7.1 of this MEP and corrected for backpressure, if necessary, as noted in Section 6.1.7.2 of this MEP—shall be corrected for high temperature. The pressure relief valve manufacturer shall be consulted, since corrections vary with different manufacturers. Some typical corrections are as follows:

Operating Temperature		**Increase in Ambient Set Pressure**
°C	**°F**	**Percent**
-268 to 93	-450 to 200	None

Operating Temperature		Increase in Ambient Set Pressure
°C	°F	Percent
94 to 232	201 to 450	2
233 to 482	451 to 900	3
Over 482	Over 900	4

4. Multiple or supplemental pressure relief valves used for an individual relief load, shall be set in accordance with the requirements of API RP 520 PT I.

5. Single-spring pressure relief valves located in compressor or pump discharge lines shall be set above the maximum pulsation pressure or 15 percent above the operating pressure, whichever is greater. When this is not possible because of equipment design pressure or specified operating pressure level, pilot-operated valves shall be used. Resilient seated valves may be considered with Mobil approval.

6.1.8. Relief Valve Selection

The following are conditions for the selection of standard spring-loaded pressure relief valves versus pilot-operated pressure relief valves for low molecular weight service at temperatures above 177°C (350°F):

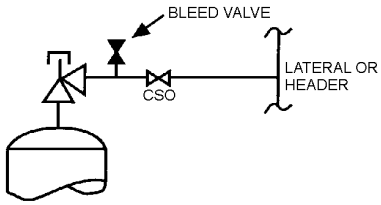
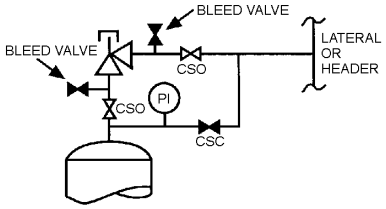
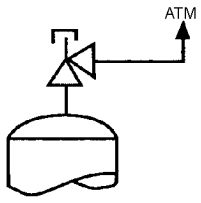
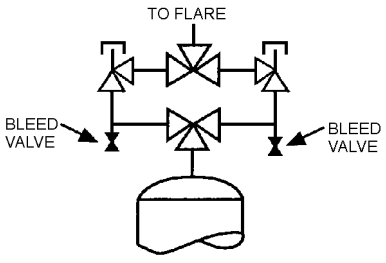
Service Conditions			Relief Valve	
MW	Temp	Operating Pressure	Set Pressure	Type Valve to be Used
<10	>177°C (350°F)	<90% of set	5170 kPa gauge max (750 psig)	Standard spring-loaded
<10	>177°C (350°F)	N/A	>5170 kPa gauge (750 psig)	Pilot-operated

	Service Conditions			Relief Valve	
	MW	Temp	Operating Pressure	Set Pressure	Type Valve to be Used

6.1.9. Pressure Relief Valve Sizing

Pressure relief valves shall be sized in accordance with API RP 520 PT I.

Table 1: Examples of Block Valves with Pressure Relief Valves to Permit Removal of Pressure Relief Valves for Maintenance or Testing

Pressure Relief Valve Installation	Process Equipment Condition	Block Valve Arrangement	Example
Relief to flare	Equipment is shut down, drained, depressured and isolated	A block valve is installed on the discharge side of the relief valve (inlet to flare header). (Note 1)	
Relief to flare	Equipment is on-line and running	Block valves are installed on both the discharge and the inlet sides of the relief valve, together with a bypass valve around both. A pressure gauge is installed on the upstream side of the bypass valve. (Notes 2 and 3)	
Relief to atmosphere	Equipment is shut down, drained, depressured and isolated	No block valve is required.	
Relief to flare	Equipment is on-line and running	Dual safety selector valves with dual relief valves are installed.	

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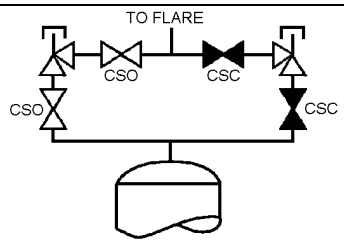
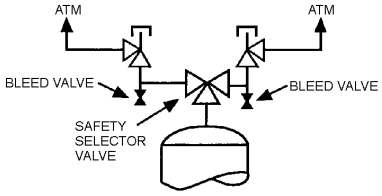
Pressure Relief Valve Installation	Process Equipment Condition	Block Valve Arrangement	Example
Relief to flare	Equipment is on-line and running with Administrative controls to ensure one PSV is on-line	Dual relief valves with inlet and outlet block valves.	
Relief to atmosphere	Equipment is on-line and running	A safety selector valve with dual relief valves is installed.	

NOTES:

1. Block valve shall be car sealed or locked open.
2. Block valves shall be car sealed or locked open and the bypass valve shall be car sealed or locked closed.
3. Personnel shall be stationed at the bypass valve when the pressure relief valve is removed, until the pressure relief valve has been reinstalled and the block valve is reopened and is re-car sealed. (Reference ASME SEC VIII D1 AB and ASME SEC VIII D1 BB.)

6.1.10. Special Protection for Devices in Dirty or Fouling Service

Pressure relief devices in dirty, waxing, polymerizing or other service where fouling is likely shall be provided with a continuous flushing system on the underside of the seat or disk.

6.1.11. Vacuum Relief

The possible need for vacuum relief on all vessels and systems shall be considered. Suitable protection may be provided by vacuum-breaking systems, inert (non-condensable) blanketing systems, etc. As an alternative to vacuum relief, pressured equipment may be designed for full vacuum conditions.

6.2. Piping

Pressure relief system piping shall be designed in accordance with MP 16-P-01. The pressure drop for pressure relief piping shall be determined using equations specifically developed by industry for relief and flare systems and shall be subject to Mobil approval. The pressure relief piping for new pressure relief headers and systems shall be sized so

that pressure relief valve backpressure generated after the valve opens is no greater than the following.

- New Facilities
  - Conventional Valves: 10 percent of set pressure (21 percent of set pressure for ASME designed vessels under fire load conditions only)
  - Balanced Bellows Valves: 30 percent of set pressure
  - Pilot Operated Valves: 30 percent of set pressure
- Existing Facilities
  - Conventional Valves: 10 percent of set pressure (21 percent of set pressure for ASME designed vessels under fire load conditions only)
  - Balanced Bellows Valves: 50 percent of set pressure (valve manufacturer shall be consulted to verify maximum allowable backpressures)
  - Pilot Operated Valves: 50 percent of set pressure

6.2.1. Relief Valve Sizing

Relief valve sizing shall be based on instantaneous loads rather than decaying loads. Credit may only be taken for decaying loads if a dynamic load analysis is performed in accordance with Appendix C of this MEP.

6.2.2. Flare System Piping

Flare system piping shall be designed, anchored and guided to resist the forward, lateral and upward dynamic forces that develop at bends as a result of high-velocity vapors and condensed liquids. Flare pipelines that are supported by pipe shoes shall have shoes no shorter than twice the calculated growth of the piping or a minimum of 457 mm (18 in). The piping shall include expansion loops to accommodate sudden thermal expansion or contraction in accordance with MP 16-P-01. Expansion joints may be used only with Mobil approval.

Where there is a wide range between PSV set pressures, independent high and low-pressure relief systems shall be considered.

6.2.3. Relief System Piping

To prevent accumulation of liquids in the system, relief system piping shall be free of pockets and shall slope downward toward the flare knockout drum for good drainage. The slope shall be at least 2 mm/m ($^1/_4$ in/10 ft), plus the calculated deflections of empty pipe between two supports. Where it is not practical to design the lines with a continuous slope, changes in elevation may be made, subject to Mobil approval. Such changes shall be made using knockout drums designed in accordance with Section 6.3 of this MEP.

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6.2.4. Insulation

Insulation of pressure relief headers may be required for personnel protection, sound levels or process reasons. The use of insulation and heat tracing to avoid ice accumulation within the pressure relief header shall be considered. Insulation requirements are included in MP 34-P-10.

6.2.5. Materials

Suitable alloy steel shall be used in applicable portions of pressure relief systems, including pressure relief valves, if large quantities of light hydrocarbons are to be vented into the system. Auto-refrigeration of these gases can result in freezing and ruptures of carbon steel pipe at metal temperatures of -29.9°C (-20°F) or lower. Pressure relief valves shall be heat traced, not limited to steam, if auto-refrigeration is expected.

Gate valves in the flare unit headers shall be installed with the valve stem in the horizontal position to prevent blockage in the event that the gate separates from the stem (see Figure 1).

6.2.6. System Pipe Sizing

Following are general guidelines for the sizing of pressure relief system piping:

- Inlet piping for a pressure relief valve shall be no smaller than the valve inlet nozzle.
- Leads shall be sized for the maximum individual pressure relief load determined in accordance with Section 6.1.6 of this MEP. Leads shall be no smaller than the outlet sizes of the pressure relief valves.
- Laterals shall be sized for the maximum individual lead load or the simultaneous relief loads from one cause, whichever is greater. Laterals shall be no smaller than the largest lead they serve.
- Unit headers shall be sized for the maximum individual load or simultaneous relief loads that are generated within the process unit as a result of a single failure, whichever is greater.
- Main headers, flare headers and flare stacks shall be sized for the maximum emergency relief load.

6.3. Flare and Vent System Knockout Drums (Scrubbers)

Knockout drums shall be sized to handle the maximum emergency relief load. In sizing the flare knockout drum, credit shall be taken for liquids removed in upstream knockout drums.

Mechanical design of drums shall be based on ASME SEC VIII D1 AB, ASME SEC VIII D1 BB and MP 12-P-01.

The design of gravity knockout drums shall be based on the method recommended in API RP 521. A knockout drum shall be sized to separate droplets 450 µm (180 mil) and greater at maximum relief load and at reduced flow rates. The drum shall be large enough to allow disentrainment above the liquid present in the drum. The maximum liquid level in the drum shall be set at 229 mm (9 in) above the heating coils (see Figure 2) or the level corresponding to condensation and carryover from 20 minutes of flaring at maximum emergency relief load conditions, whichever is greater. Each case assumes that no pumps are running. The minimum level shall be just above the top of the coils.

6.3.1. Instrumentation

The following instruments are the minimum requirements for knockout drums:

1. Temperature indicator mounted below the low-liquid level
2. Pressure gauge
3. Independent high-level alarm with annunciation in the control room
4. Level gauge
5. Level switches to start/stop the pumps
6. Low-low-level switch to close the control valve to prevent vapor from entering the slops system
7. Independent low-low-level alarm with annunciation in a constantly manned location (i.e., control room)

6.3.2. Pumps

Knockout drums shall be provided with heating coils to prevent freezing and to vaporize condensables.

- The drums shall be provided with automatic liquid level controlled pumps (see Figure 2).
- A two-pump system, with different types of drivers for each pump, shall be provided. An alternate driver arrangement requires Mobil approval.
- Each pump shall be sized to empty a half-full knockout drum within two hours and shall have a minimum capacity of 95 liters/min (25 US gpm).
  - Pump discharge piping shall be designed for simultaneous operation of both pumps.
  - A separate water drain on a boot underneath the knockout drum may be used, if required (see Figure 2).

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  - It may be more economical to supply small onsite liquid knockout drums in each unit and have the main flare knockout drum handle only condensation that occurs in the main flare header.

- Liquid knockout drums shall be provided at all system low points (for example, at road crossings).

6.4. Flashback Protection

Protection shall be provided against flashback from the flare tip into the flare stack and into the pressure relief system. The preferred method of protection is by the use of a small, continuous gas purge in conjunction with a buoyancy seal or kinetic seal. Flame arrestors are not acceptable. They are subject to fouling and may permit seepage of air back to the flare header, resulting in a flammable mixture and, if pyrophoric iron is present, possible ignition. The following common methods of flashback protection (purge gas, buoyancy seals, kinetic seals, water seals and diversion water seals) are discussed below:

1. Purge Gas: The recommended method of connecting the purge gas supply to the flare is shown in Figure 1. The following equation shall be used as an initial estimate of the purge gas rate required for an open pipe flare.

$$PGR = \frac{bd^3}{M^{0.565}}$$

Where:

PGR = purge gas, m^3/h (ft^3/h)

b = constant for flare stacks 457–914 mm (18–36 in) in diameter (1.2×10^{-5} [metric]; 7.0 [customary])

d = stack diameter, mm (in)

M = molecular weight of purge gas

When purge gas is used in conjunction with a buoyancy seal or kinetic seal, a smaller amount of gas is needed.

Purge requirements for proprietary flare tips shall be established with the supplier.

Plugged vents for purging of the pressure relief system prior to startup shall be installed as shown in Figure 1. After startup, a small stream of continuous purge gas need only be injected into the main header at the point farthest from the flare. A flow meter with a low-flow alarm shall be installed at the purge gas injection point.

A larger amount of purge gas is usually required after a hot release to prevent air from entering the system when the system gas inventory cools and contracts. This additional gas injection shall be on automatic temperature and pressure control (see Figures 3 and 4). The rate of gas injection may be estimated as follows:

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a) Calculate the average gas temperature in the flare system under flowing conditions as outlined in Mobil's Engineering Design Handbook, Volume 2, Process Heat Transfer.

b) Assume that weather conditions do not change before or after a hot release.

The reduction in the flare system gas volume as a result of cooling can be calculated from the difference between the average flowing temperature and the ambient temperature.

Inert gas purge capability shall be included in calculating the purge gas requirements, in order to empty the flare headers, stack and tip in the event of a flare shutdown.

2. Buoyancy Seal (Mol Seal): This gas sealing device uses the density difference between air and gas to prevent air from flowing back into the flare header. It is installed on the flare stack just below the flare tip. The design includes a drain to grade level with a suitable seal for removal of trapped condensables. The mol seal shall have a handhole near the drain line to permit cleaning when the seal or the drain line is plugged. The bottom of the mol seal and the entire drain line shall be electrically traced and insulated or steam traced and insulated in areas where temperatures fall below 2°C (35°F). If the knockout drum is immediately below the flare stack, the drain line can be run directly to it. Valves on these drain lines shall be spring loaded so they remain closed unless held open.

3. Kinetic Seals: All major flare manufacturers make proprietary seals for their own flares (John Zink's Airrestor, National Air Oil (NAO) Fluidic Seal, Kaldair's Diode Seal, etc.). All of these seals use the upward velocity of the purge gas to reverse the flow of oxygen that penetrates the tip. These seals have several advantages over other seals (cheaper, less weight, less pressure drop), but they cannot be used effectively where the flow of purge gas could be interrupted. Kinetic seals will permit air ingress into the system immediately after purge flow ceases, whereas mol and water seals will prevent air ingress for several hours after the purge gas supply is lost.

4. Water Seal: A diversion water seal is used to divert large releases from the operating flare to the emergency flare. When used, the water seal shall be installed in accordance with Figures 3 or 4 and Figure 5. In cold climates a water seal may freeze, resulting in blockage of the flare system. A water seal will prevent air ingress into the pressure relief system, but will not prevent air ingress into the flare stack after purge flow ceases. A low-temperature alarm shall be installed on the water seal and its standpipe in freezing climates.

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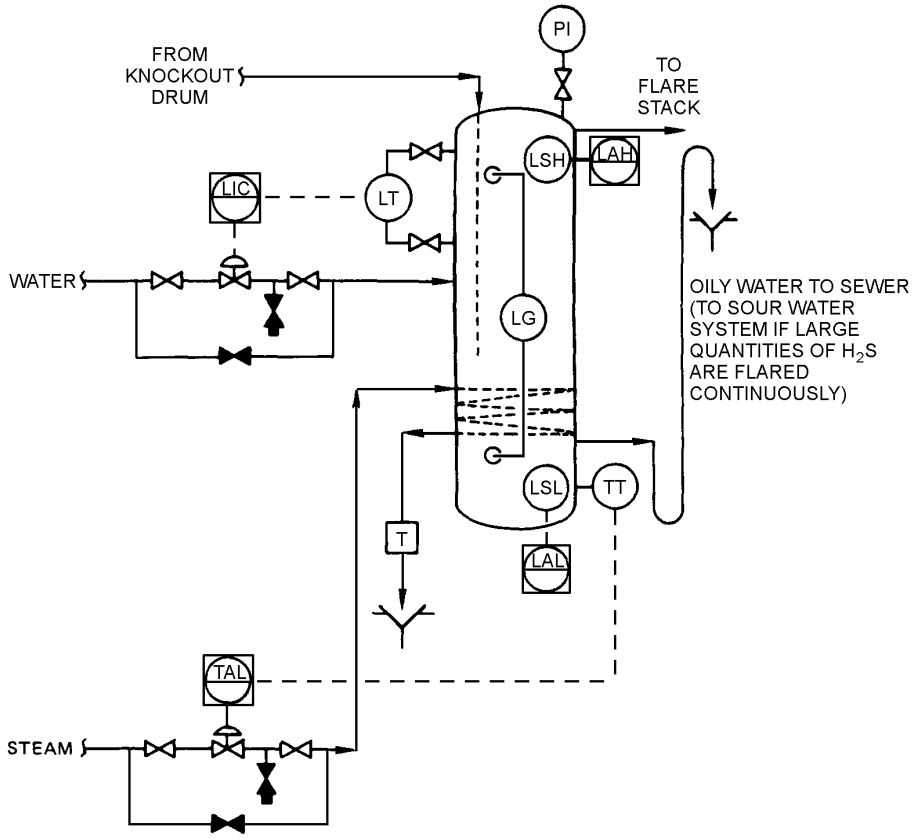

Figure 5: Water Seal Drum

6.5. Flare Stacks and Tips

A restricted access zone shall be established around the flare stack in order to control the location of equipment and access of personnel. The restricted access zone shall be determined based on the radiation levels listed in the Table 2.

Table 2: Allowable Radiant Heat Intensities in W/m^2 (Btu/hr/ft^2) Excluding Solar Radiation

		In Plant		Public
		Appropriate Clothing*	**Without Appropriate Clothing***	
Continuous Release		1105 (350)	790 (250)	790 (250)
Emergency Releases	Travel time to shelter:			
	6 sec	9465 (3000)	3150 (1000)	
	1 min	6300 (2000)	3150 (1000)	
	3 min	4730 (1500)	1580 (500)	1580 (500)
	No shelter available	1580 (500)	790 (250)	790 (250)
	Equipment exposure only	15,770 (5000)		
	Volatile liquids tanks, API separator, CCB	2365(750)		NA

***Definition:** Appropriate clothing is clothing such as coveralls, long sleeved shirts, pants, hard hat, etc., which can shield all body areas except for the face and hands from exposure to flare radiant heat.

The flare stack diameter shall be equal to or greater than the flare header diameter.

Flare stack height, which is usually determined by allowable radiant heat intensities at grade, shall be calculated in accordance with the procedure given in Appendix D of this MEP. Flare stack height can also be governed by expected dispersion.

The minimum diameter for pipe tips shall be calculated in accordance with the procedure given in Appendix D of this MEP.

Requirements for flare tip repair or replacement are as follows:

1. When tip repair or replacement is necessary, the operating flare can be isolated from the emergency flare header by closing and blinding the valve that is provided (see Figure D–1). Discharge of vapors from normal operations can then be temporarily diverted to the emergency flare for smokeless burning. Immediate repair or replacement of the operating flare tip can proceed without shutting down the process unit.

2. Multiple flares are another means of providing for onstream flare tip replacement. Two flares of 50 percent capacity will allow flare tip replacement with the process

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unit throughput decreased by approximately 50 percent, provided that the two flares are:

a) Properly spaced to meet allowable radiant heat intensities at grade (see Table D–1)

b) Equipped with diversion water seals

c) Spaced to meet allowable radiant heat intensities for personnel who are replacing the flare tip

3. Similarly, two flares of 100 percent capacity will allow flare tip replacement without decreasing any process unit throughput. In either case, one flare shall be used as an operating flare for smokeless burning of normal operating releases. Diversion seals on multiple flares will allow either flare to be used as an operating flare.

6.6. Pilots and Ignitors

All flares shall be provided with continuously operating or pulsating pilots to prevent flameout and to ensure that all releases to the flare are burned. The following guidelines shall be used in determining the number of pilots to be used for each flare:

Flare Sizes

mm	**in**	**No. of Pilots**
Up to 305	Up to 12	1
305–610	12–24	2
610–1220	24–48	3
Over 1220	Over 48	4

Flame-front and self-inspirated igniter/pilot gas pressures shall be regulated at 103 kPa gauge (15 psig). Piping shall be sized to allow flow at approximately 3.5 std m³/h (125 scf/h) per pilot. Typical pilot installations are shown in Figures 3 and 4. Combination igniter/pilot gas pressure shall be regulated at 69 kPa gauge (10 psig). Product sweet gas, high-pressure trap gas or bottled propane shall be used for pilot gas.

6.6.1. Pilot Monitoring System

A pilot monitoring system shall be provided.

- The system shall be arranged to alarm in the control room on loss of flame.
- Pilot monitoring shall be by thermocouples or flame ionization monitoring.
  - Thermocouples shall be mounted on the pilots to alarm on loss of the pilot flame.
  - Thermocouples shall be positioned so that they are in the reducing part of the pilot flame.
  - Thermocouple components shall be Chromel-Alumel in Inconel sheaths.
  - Flame ionization monitors shall be installed per the manufacturer's specifications.

6.6.2. Piping

Pilot gas piping may be copper tubing to a point 3 m (10 ft) below a combination igniter/pilot. The remainder of the piping and the igniter/pilot shall be fabricated entirely of Type 309 or Type 310 stainless steel.

Piping to other types of pilot heads shall be carbon steel to a point 3 m (10 ft) below the pilot. Pilot heads and piping shall be constructed of Type 309 or Type 310 stainless steel to a point 3 m (10 ft) below the pilot.

6.6.3. Pilot Ignition

A means of remotely igniting the pilots, which in turn will light the flare gas, shall be provided. Three systems commonly used are combination igniter/pilots, flame-front generators and self-inspirated systems.

1. Combination Igniter/Pilots: New combination ignition system/pilots are available for flares of all types. Automatic re-ignition using integral flame ionization monitoring allows this unit to be used with propane or intermittent fuels such as scrubbed well-gas. Gas supplies may be operated manually or controlled automatically when an electric solenoid valve is used with the system. If electric power is interrupted, the system shall automatically cycle to ignite when the power is restored.

   Pilot gas shall be transported via minimum 6 mm ($^1/_4$ in) diameter tubing into the igniter/pilot tip.

   A maximum of 10 igniter/pilots may be controlled with a single control panel. The igniter/pilots may be used in a vertical or horizontal position.

2. Flame-Front Generators: In the flame-front generator, the size of the ignition piping from the ignition control panel to the flare pilot shall be NPS 1 (NPS = Nominal Pipe Size, inches), with no change in size anywhere along its route. The ignition control panel shall be located

away from the flare in a safe, accessible location that is free from high radiation levels and free from the hazard of liquid carryover.

The ignition panel requires compressed air at 103 kPa gauge (15 psig), fuel gas at 103 kPa gauge (15 psig) and electricity at 110–440 volts AC. The air and gas are mixed at the panel and swept through the NPS 1 pipe to the flare pilot. When the ignition line is filled with a combustible mixture, the mixture is spark-ignited to generate a flame front that travels through the NPS 1 piping to the pilot.

3. Self-Inspirated Systems: In the self-inspirated ignition system, an eductor is mounted in the igniter piping near the base of the flare. Fuel gas is piped to the eductor and air is inspirated with the fuel. The pipeline running from the eductor to the pilot is NPS 2 and shall not exceed 37 m (120 ft) in length. Directly above the eductor is a cross with a sparking device mounted inside. When the NPS 2 line is filled with a combustible mixture, the sparking device is actuated. The eductor and sparking device shall be shielded from the radiation of the flare and from any possible liquid carryover. Ignition heads shall be constructed of Type 309 or Type 310 stainless steel.

6.7. Combustion Assistance (Steam/Air) Systems

1. In most installations, smokeless flaring is required for small discharges of purge gas, relief valve leakage that occurs during normal operations and discharges that are encountered during unit startup and shutdown. Smokeless flaring is not required for pressure relief of short duration during a serious emergency, such as power failure. Environmental regulatory agencies dictate the degree of smokeless operation required. However, the operating flare is usually designed for "smokeless" burning of approximately 10–30 percent of its maximum emergency discharge rate.

2. Providing steam for the smokeless burning of gases from large compressors that have shut down may not be feasible. Agreement that a compressor shutdown is an emergency and, therefore, does not require smokeless burning shall be obtained from the local air quality control authorities.

3. Smokeless flaring is usually accomplished by injecting steam into the vapor at the flare tip. The vendor shall be consulted to determine steam rate. The data shown in Figure 6 can be used to estimate steam loads and to size steam lines. Numerous acceptable proprietary injection schemes are commercially available to reduce steam use. Steam control valves shall be located as close as possible to the flare stack to minimize lag time.

4. When the gases that are being flared contain unsaturated hydrocarbons, the steam requirements may be substantially higher (see API RP 521).

5. Steam injection to the flare may be controlled either manually or automatically. A thermal sensing control located in a flare header is not acceptable.

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6. Mobil noise requirements and local noise requirements shall be met for discharges up to the maximum smokeless burning rate. Noise abatement is not usually required for the less frequent emergency rates greater than the smokeless burning rate.

7. Provision shall be made for injection of air or water into the steam lines to permit flow to the nozzles when the steam supply is down. Steam keeps the lines, ring and nozzles cool. Damage will result if the flare is burning without steam flow.

8. Smokeless flaring can also be achieved by injection of high-pressure gas or air into the relief gas stream. Special multipoint or high-velocity flares can also burn smokelessly. Where the steam capacity is inadequate to allow smokeless burning, particularly when unsaturates are being burned, suppliers shall be required to submit alternate bids for steam-assisted pipe flares.

9. Air assist technology is also available to allow smokeless flaring without the use of steam. Air assist designs are available from several vendors.

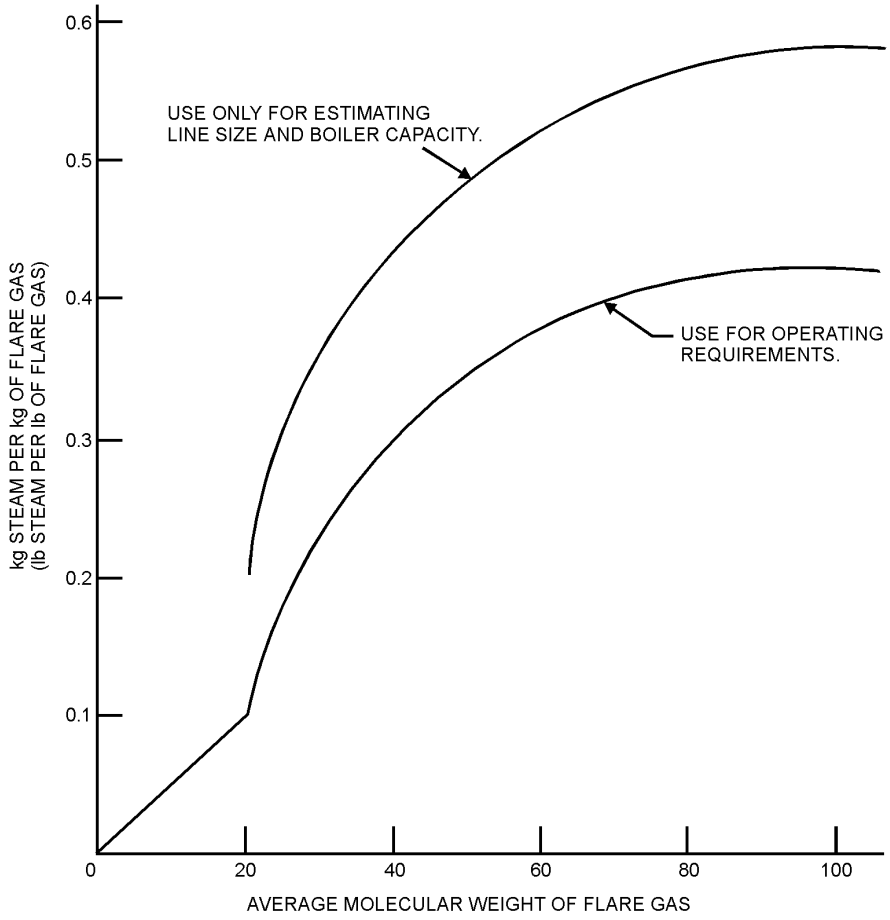

Figure 6: Dispersant Chart for Smokeless Flaring

6.8. Alternative Flare Designs

An enclosed ground flare (such as a Kaldair Concealed Flare, John Zink ZTOF or one of NAO's NPAC series or equivalent) may be used in place of the operating flare discussed in Section 6.5 of this MEP. This type of flare shall be considered when local regulations require nonluminous burning or when vibration problems exist. Enclosed flares are limited to maximum burning rates of approximately 90,900 kg/h (200,000 lb/h) for each flare and are significantly more expensive than elevated flares.

Staged ground flares (see Figure 7) may be used, especially where smokeless flaring of unsaturated hydrocarbons is desired without steam use. These flares may be partially enclosed or open and can be located in a burn pit. These flares usually require large site areas.

The staging system is critical and shall have a safety bypass around control valves in the event of loss of actuator power (refer to MP 32-P-07). Rupture pins are the preferred bypass (see Figure 7).

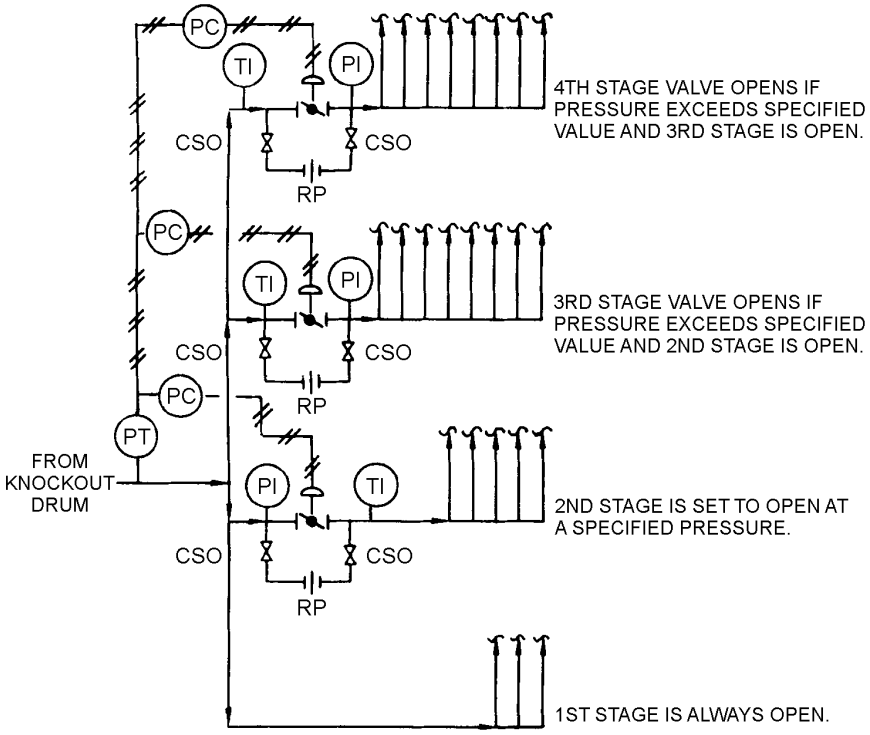

Figure 7: Staged Multi-Tip Flare

NOTES:

1. All valves are bypassed with rupture pins (RP).
2. System is designed to handle flow from maximum emergency relief with all valves open.
3. Number of tips and stages shown is for illustration only.

6.8.1. Comparison of Proprietary Flares

Installation of other proprietary flares can result in savings in steam, purge gas and radiation. When bidding on a job, suppliers shall be encouraged to present alternate bids that indicate the advantages of their proprietary models compared with pipe flares. Examples of proprietary flares include Birwelco's Sonajet and Kaldair's entire line of Coanda Effect flares or equivalent. Each design has inherent advantages and disadvantages, as indicated in the following chart:

Table 3: Proprietary Flares

Tip Type	Typical Uses	Advantages	Disadvantages
Standard–Pipe/Utility	Offshore E&P with low MW gases	Lower installed cost	Smoke generation potential
Steam assist	Smokeless flaring requirements	Low-cost smokeless flaring	Higher maintenance Requires a steam source High noise
Air assist	Smokeless flaring requirements	No utility requirements (i.e., steam)	Higher maintenance Requires shielding to maintain blowers Higher radiation levels
Multipoint/staged ground flare (e.g., LRGO)	Smokeless flaring of saturated hydrocarbons	Low radiation	Highly instrumented Potentially higher installed cost Larger plot space
Enclosed ground flare (e.g., ZTOF)	Incineration of waste gas, limited plot space	Low plot space (floating production systems) Low noise Low radiation	Max of 75 MMSCFD (90,000 kg/h) Higher installed cost
High-velocity flare tips	Intermittent flaring service	Low radiation	High noise High backpressure in relief header Higher installed cost

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6.9. Atmospheric Relief Vents

An atmospheric relief vent is a vertical pipe on the outlet of a pressure relief valve, used for atmospheric discharge of vapor or gas to a safe location. Atmospheric relief vents shall be designed and constructed as follows:

1. Atmospheric vent pressure drops shall be calculated using the relief loads determined in Section 6.1.6 of this MEP. Where the discharge velocity of the vapor is to be maintained at 152 m/s (500 ft/s) or higher, the end diameter of the vent pipe shall be reduced for a length equal to three pipe diameters to achieve this velocity. Standard concentric reducers shall be used. Discharge velocity shall not exceed 80 percent of sonic velocity.

2. A high-level alarm shall be provided if there is a possibility that liquid will flood the vessel protected by the PSV during an upset condition. The initial warning given by this type of alarm may allow the operator to prevent a liquid discharge.

3. Atmospheric vent pipes shall be designed and supported to prevent pipe failure caused by kinetic forces that develop during a discharge.

4. A 6 mm ($^1/_4$ in) drain shall be provided at the low point in an atmospheric vent to prevent the collection of condensate, rain or snow in the discharge pipe. The drain shall be protected from freezing and shall be piped for safe disposal so that the opening will not endanger personnel or, in the event of fire, impinge on a vessel surface.

5. Snuffing steam or inert gas connections shall be provided on all atmospheric vent stacks that handle flammable vapors. Steam or inert gas is required to extinguish fires that may start at the vent outlet. Snuffing steam connections may not be required in gas plants located outside refineries or in offsite pressure storage vessels, where steam for this purpose is usually not available.

6. Flame arrestors shall not be installed on atmospheric vents. Arrestor elements can become plugged with atmospheric dust, process products, products of corrosion or ice during cold weather.

7. Atmospheric relief vents shall terminate to satisfy all of the following:

   a) At least 2 m (6 ft) above the highest adjacent structure or tower

   b) At least 4 m (12 ft) above the highest adjacent platform

   c) At least 5 m (15 ft) above grade

8. Located at least 15 m (50 ft) or 120 pipe diameters, whichever is greater, away from the nearest platform, structure or tower when located at an elevation lower than the platform, structure or tower.

9. Located at least 30 m (100 ft) or 120 pipe diameters, whichever is greater, away from the tops of flue gas stacks or other ignition sources, regardless of the atmospheric vent elevation.

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10. The effects of radiant heat resulting from ignition of the vapors/gases during discharge shall be considered when locating the atmospheric vent pipe and its termination point.

6.10. Vent Stacks

A vent stack is vertical pipe that transfers discharged vapor and/or gas, from a main collection header to a safe, elevated location for discharge to the atmosphere. Vent stacks shall comply with the requirements of Section 6.9 of this MEP and the following:

1. A knockout drum (scrubber) shall be provided where liquids can enter or condense in the relief system (see Section 6.3 of this MEP). The knockout drum can be manually drained if the drum is sized to handle the worst case liquid release and appropriate level instrumentation is provided, including a high-level alarm which annunciates in a constantly manned location. Knockout drums in unattended locations shall be provided with automatic level control.

2. Flashback protection shall be provided in accordance with Section 6.4 of this MEP.

7. Vapor Depressuring

7.1. General

Vapor depressuring is a fire protection method that is used to reduce pressure by voluntary, rapid removal of vapors from pressure vessels, if there is a fire. This method is used to reduce pressure in pressure vessels that would be weakened by excessive heating caused by fire or excessive temperature due to other causes. It may also be used as a temporary operating control during startups, shutdowns and short-term upsets by reducing pressure to prevent a pressure relief valve discharge. However, vapor depressuring shall not be used as a permanent operating control in lieu of correcting the causes of a unit upset.

Vapor depressuring requirements for vessels shall be as follows:

1. Vessels shall be depressured to 690 kPa gauge (100 psig) or to 50 percent of the design pressure, whichever is less. The maximum time allowed to depressure a vessel or system shall be two minutes per 3 mm ($^1/_8$ in) of vessel wall thickness, but shall not be less than six minutes. Depressuring time shall not exceed 15 minutes, except with Mobil approval.

2. Vapor depressuring may be impractical when the vessel design pressure is less than 690 kPa gauge (100 psig), because valves and piping can become unreasonably large and costly. It is also impractical when the vapor depressuring load governs the size of pressure relief and flare headers. When vapor depressuring is not practical, vessels may be insulated (see MP 70-P-05) to reduce the vapor depressuring load or they may be protected by other means, such as water sprays (see MP 70-P-01). The use of either of these alternatives requires Mobil approval.

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7.2. Depressuring Flowrate

To calculate the vapor flowrate that is needed to accomplish depressuring, the maximum expected operating pressure of the vessels under consideration shall be used as the initial pressure and the pressure specified in Section 7.1.1 as the final pressure. When estimating flows for sizing depressuring valves and piping, consideration shall be given to:

- The effect of the initial depressuring rate on the closed pressure relief system and flare
- The average depressuring rate used to determine depressuring time
- The variations in temperature, pressure, vapor composition and possible liquid entrainment during the depressuring period on downstream flare system components
- The effect of the initial depressuring rate on upstream process equipment

7.3. Depressuring Valves

7.3.1. Types of Valves

Vapor depressuring valves may be pneumatically or hydraulically actuated or manually operated with remote indicators to show valve position. Pneumatically or hydraulically operated valves shall open on accidental actuating fluid failure, with provision to maintain pressure on the diaphragm or hydraulic cylinder in the event of accidental actuating fluid failure. When pneumatically or hydraulically operated control valves are used, they shall be of the tight shutoff type (refer to MP 32-P-04). Block valves that are car sealed open shall be provided to facilitate depressuring valve maintenance.

7.3.2. Valve Arrangement

Vapor depressuring valves are typically arranged as follows:

1. Normally, a pneumatically or hydraulically operated depressuring valve is installed in a bypass around the pressure relief valve. When depressuring valves are used in this location, they shall be operated from the control room or from a remote, accessible location at grade level outside the fire area that contains the vessel or the train of process vessels protected by the valve. The valve, its pneumatic or hydraulic operator and the portion of supply lines located within the expected fire area shall be fireproofed in accordance with MP 70-P-05. The remaining supply lines shall be designed and installed to withstand the heat of the fire for 30 minutes.

2. Pneumatically or hydraulically operated vapor depressuring valves may be placed outside the fire area when the fireproofing requirements for valves, operators and their supply lines inside the fire area are not economical.

3. Manually operated vapor depressuring valves, if selected, shall be installed in a safe, accessible location outside the fire area that contains the vessel or train of process vessels protected by the valve.

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4. On towers or vessels containing demister pads or packing, the depressuring valve shall be located so that dislodgment of the demister pad or packing will not obstruct the valve, or mechanical reinforcement shall be provided to prevent dislodgment.

5. With pneumatically operated vapor depressuring valves, an air/nitrogen accumulator bottle with a check valve on the supply line shall be installed to prevent depressuring of the unit in the event of an air/nitrogen system failure.

7.3.3. Sizing

In sizing depressuring valves, it shall be assumed that heater burners are shut off, reboilers are shut down and normal flow in the vessel has ceased. Calculate the depressuring load using the method given in API RP 521. Vapor depressuring valves shall not exceed the capacity of the closed pressure relief system and flare. Alternatively, they may be programmed to depressure the required load at a uniform flowrate that is lower than the capacity of the closed pressure relief system and flare throughout the required time period. The second procedure will prevent overloading of the closed pressure relief system and the flare (see MP 32-P-08) or damage to upstream equipment.

When a single depressuring valve serving more than one vessel is sized, equipment other than the vapor depressuring valve (including control valves) shall not restrict the required depressuring flow. A single fractionating column and its associated equipment or other minor groups of equipment fall into this category.

Depressuring valves are not intended to meet the requirements of the ASME Boiler and Pressure Vessel Code. These valves provide protection in cases where a vessel might rupture because of excessive heat from fire or from exothermic reactions before the pressure relief valve actuates.

7.4. Disposal of Discharge

Vapor depressuring valves shall discharge into a closed pressure relief flare or vent system. This system is preferred because fluid from depressuring valves is likely to be condensable at the end of a sustained release.

7.5. Other Considerations

7.5.1. Flare System

It is usually not necessary to size the closed pressure relief system and flare for simultaneous release of pressure relief valves and depressuring valves.

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7.5.2. Pressure Relief Valves

The pressure profile in the closed pressure relief system shall be examined under depressuring loads to ensure that the outlet flanges of pressure relief valves are not overpressured.

7.5.3. Pressure Vessels

Pressure vessels of copper, aluminum or other materials that are not sufficiently fire resistant shall have protection against fire exposure (for example, external insulation), in addition to having a vapor depressuring system.

8. Alternate Means of Process Overpressure Protection

In some situations where there are concerns regarding high flare system loading and backpressure, vapor velocity and/or flare radiation, an alternative to traditional pressure relief valve and flare system design that uses a highly reliable instrumented isolation or shutdown system may be considered.

Proactive measures to reduce or eliminate the flare load case(s) shall be identified, evaluated and, where possible, implemented prior to considering installation of an instrumented protection system.

8.1. HIPS Prerequisites

If all of the following conditions are met, a HIPS (High Integrity Protective System) may be considered for installation in a new or existing facility:

1. No proactive measures, including dynamic analysis, are available to reduce the relief load.
2. A Cost Benefit Analysis indicates that the life cycle cost of installation, testing and maintaining a HIPS system is less than the life cycle cost of a traditional PSV/Flare system.
3. A Fault Tree Analysis (FTA) is performed to verify the required Safety Integrity Level (SIL) of the system. This analysis shall be performed by an expert who is independent from the project design staff, the operating plant and the manufacturing company supplying the HIPS equipment.
4. The operating facility shall perform the preventive maintenance, testing and follow the operating procedures, as outlined in the FTA. The process equipment shall be designed to facilitate the preventive maintenance and testing as outlined in the FTA.
5. It has been recognized that applicable codes and regulations do not adequately cover the use of a HIPS system. The importance of preventive maintenance, testing,

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operating procedures and design requirements identified in the FTA shall be clearly understood and agreed to by the Business Unit Manager.

6. A PSV designed for fire case is provided to protect each vessel in addition to a HIPS system.

8.2. Consequences of Failure

The Safety Integrity Level (SIL) for each specific HIPS application shall be based on the consequence of failure of the HIPS system, as shown in the following chart:

Consequence	Example	SIL Level
Highest	No relief protection provided; significant offsite impact	SIL 3 or SIL 4
High	Relief protection is not fully hydraulically designed, flare line is undersized for worst case load	SIL 3
Medium	Relief protection is fully hydraulically designed, radiation levels exceed those recommended in Table D-1	SIL 2
Reference	Traditional PSV/Flare	Approx. SIL 2

8.3. Independent Function

A HIPS system shall function independently of the process control system. Equipment components of a HIPS system shall not be used for process control or any other purpose.

8.4. Fail-Safe Design

The design of the HIPS system shall be fail-safe. Both isolation valves shall close automatically in case of failure of any part of the system, including:

- Loss of power to any of the components
- Break or rupture of instrument (air) piping or cabling
- Loss of a sensor loop
- Failure of the logic/control system

8.5. Response Time

The response time of a HIPS system shall be such that the maximum pressure in any process component shall not exceed 110 percent of its Maximum Allowable Working Pressure (MAWP).

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8.6. Surge Pressures

Surge pressures caused by the rapid closing of HIPS isolation valves shall be taken into account in the design of both the upstream and downstream piping systems (refer to ASME B31.3). The extent of the possible surge pressures shall be estimated from the results of the dynamic simulation or pressure setting calculation.

8.7. Bypasses

Bypasses around HIPS system isolation valves shall be designated "Locked Closed," with controls on their operation consistent with those used for block valves provided for maintenance on relief valves. Operation of the bypass valves shall be explicitly studied in the reliability analysis.

9. Disposal System Design Review

9.1. New Installations

Mobil shall review and approve all pressure relief system, flare and vapor depressuring designs that are prepared by others. The detailed mechanical designs for pressure relief systems and flares shall be provided by the contractor, in accordance with this Section and local regulations.

Mobil requires the information and documents listed in Section 9.3 of this MEP. The information and documents shall be assembled in a single, complete design package and submitted to Mobil for final design review. This package shall be issued by the contractor as a technical data book after final approval by Mobil.

9.2. Existing Installations

Expansion projects generally require that new pressure relief and vapor depressuring facilities be integrated into the existing system. In such cases, the information requested in Section 9.3 shall be developed for the new facilities by the contractor from unit process flow and P&I diagrams supplied by Mobil. This information shall be included in the completed design package.

9.3. Required Information and Documents

The following information or documents shall be submitted to Mobil for preliminary review. This procedure facilitates processing of the contractor's designs before the single-design package is assembled for final review and approval.

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9.3.1. Summary Sheet

A pressure relief valve and depressuring valve load summary sheet (see Figure 8 or 9), by units, shall include the following data. Numbers match the columns in Figures 8 and 9.

1. Pressure relief valve or depressuring valve tag number.
2. Tag numbers for the major equipment that is protected. Several equipment items may exist in a protected system.
3. Equipment or system design pressure/temperature.
4. Equipment or system operating pressure/temperature.
5. Pressure relief device type, metallurgy, set pressure and discharge temperature.
6. Maximum allowable/calculated backpressure on the pressure relief valve.
7. Molecular weight of the relief stream.
8. Disposition of the discharge (to atmosphere, LP flare, HP flare, etc.).
9. Maximum individual loads due to:
    a) Local cooling water failure
    b) Power failure
    c) Blocked outlet
    d) Fire
    e) Instrument failure
    f) Steam failure
    g) Other (vapor depressuring or other)
10. Maximum simultaneous load due to:
    a) Total cooling water failure
    b) Total power failure (show mol weights, temperature and compositions separately)
    c) Total steam failure (show mol weights, temperature and compositions separately)
11. Other loads (show mol weights, temperature and compositions separately).
12. Remarks.

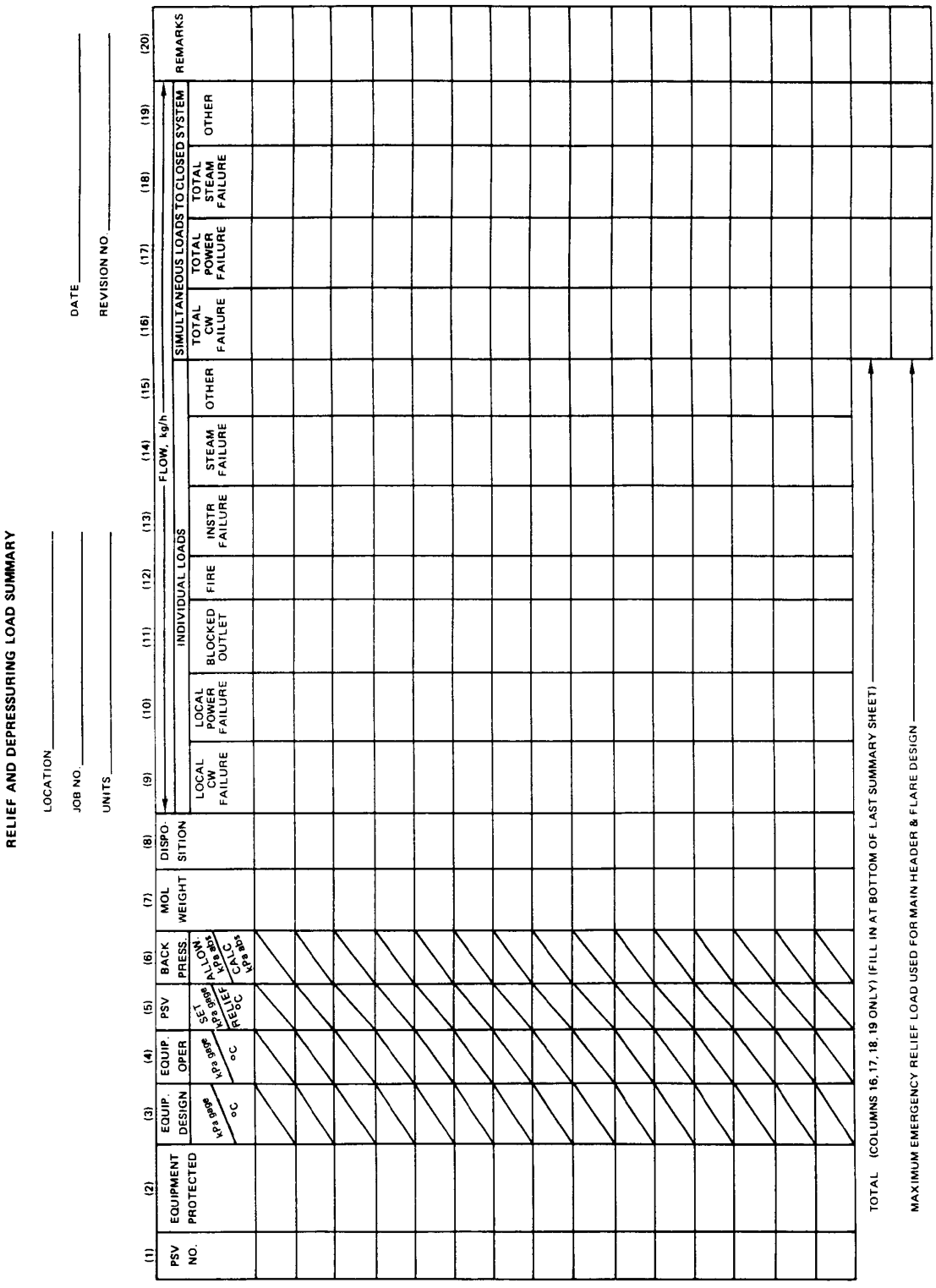
RELIEF AND DEPRESSURING LOAD SUMMARY
LOCATION
JOB NO.
UNITS
DATE
REVISION NO.
(1) PSV NO.
(2) EQUIPMENT PROTECTED
(3) EQUIP. DESIGN kPa gage / °C
(4) EQUIP. OPER kPa gage / °C
(5) PSV SET kPa gage / RELIEF °C
(6) BACK PRESS. ALLOW. kPa abs / CALC kPa abs
(7) MOL WEIGHT
(8) DISPO-SITION
(9) INDIVIDUAL LOADS — FLOW, kg/h — LOCAL CW FAILURE
(10) LOCAL POWER FAILURE
(11) BLOCKED OUTLET
(12) FIRE
(13) INSTR FAILURE
(14) STEAM FAILURE
(15) OTHER
(16) SIMULTANEOUS LOADS TO CLOSED SYSTEM — TOTAL CW FAILURE
(17) TOTAL POWER FAILURE
(18) TOTAL STEAM FAILURE
(19) OTHER
(20) REMARKS
TOTAL (COLUMNS 16, 17, 18, 19 ONLY) (FILL IN AT BOTTOM OF LAST SUMMARY SHEET)
MAXIMUM EMERGENCY RELIEF LOAD USED FOR MAIN HEADER & FLARE DESIGN

Figure 8: Typical Relief and Depressuring Load Summary–SI (Metric) Units

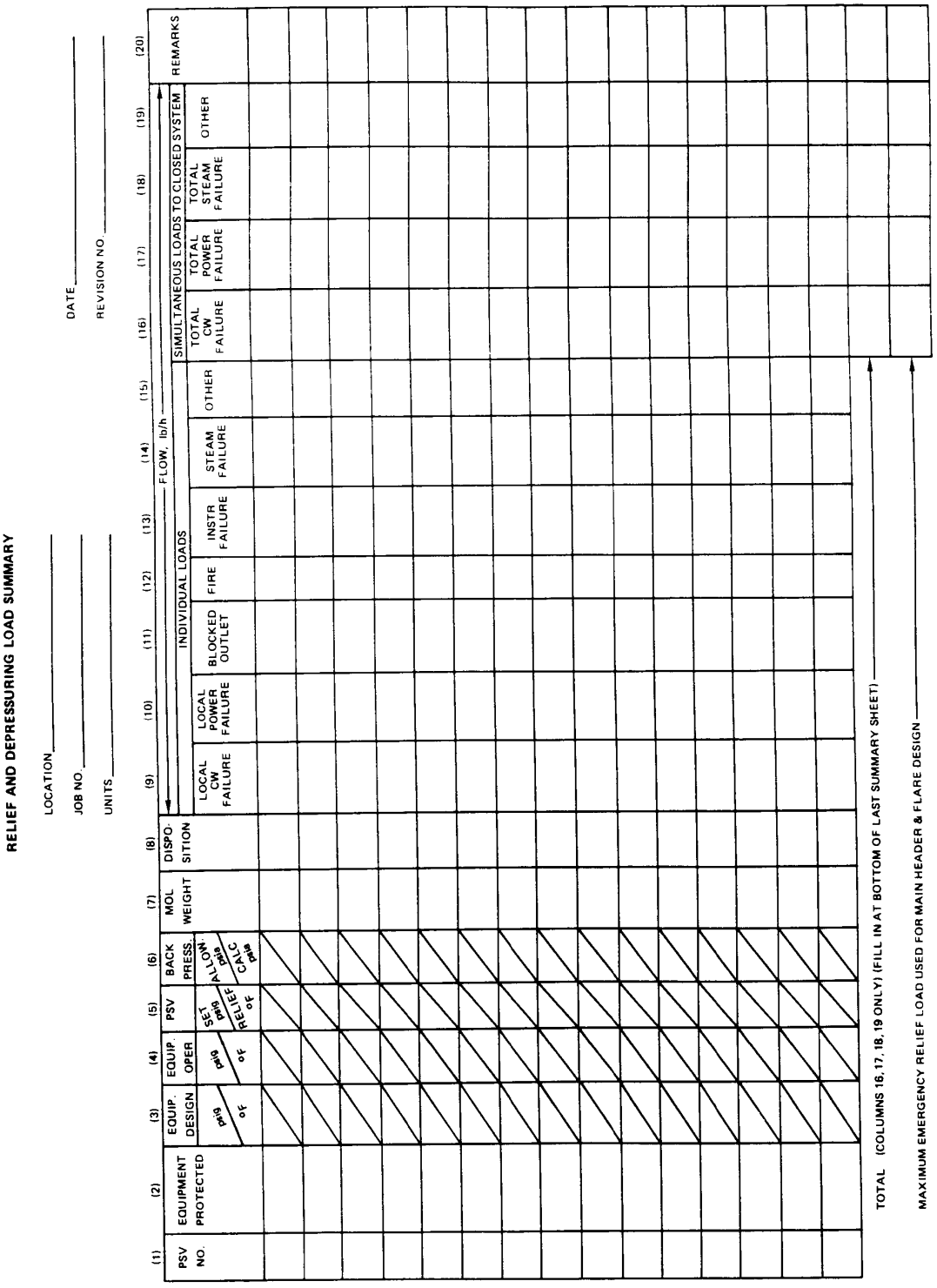

Figure 9: Typical Relief and Depressuring Load Summary–Customary Units

9.3.2. Single-Line Diagrams

Single-line diagrams, which include pressure relief and vapor depressuring valves and piping to the flare (see Figures 10 and 11), shall include the following information:

- Line sizes and line slope
- Equivalent lengths of line segments
- Vessel numbers
- Pressure relief and depressuring valve numbers

Show all pressure relief valves that are connected to the closed system. Identify those that simultaneously contribute to the maximum emergency relief load that is used to design the main header flare knockout drum, flare stack and tip. Show all depressuring valves.

9.3.3. Flare System P&I Diagrams

Flare P&I diagrams shall show the following data:

1. Flare stack height
2. Flare stack diameter
3. Flare tip diameter
4. Knockout drum size, pumpout facilities and liquid level
5. Type of flashback protection
6. Utility supply lines
7. Pilots and igniters
8. Slope of pressure relief piping

9.3.4. Additional Requirements

Other documents required are:

1. Data Sheets: Completed data sheets (see the Mobil Data Sheets for this MEP), including the type and method of operation for depressuring valves.
2. Calculations: Pressure relief and depressuring assumptions and calculations made to establish loads and valve sizes for the three worst case contingencies.
3. Unit Diagrams: The latest unit P&IDs, process flow diagrams and plot plans.
4. Vessels: A list of vessels that require vapor depressuring (see Section 7.1 of this MEP).

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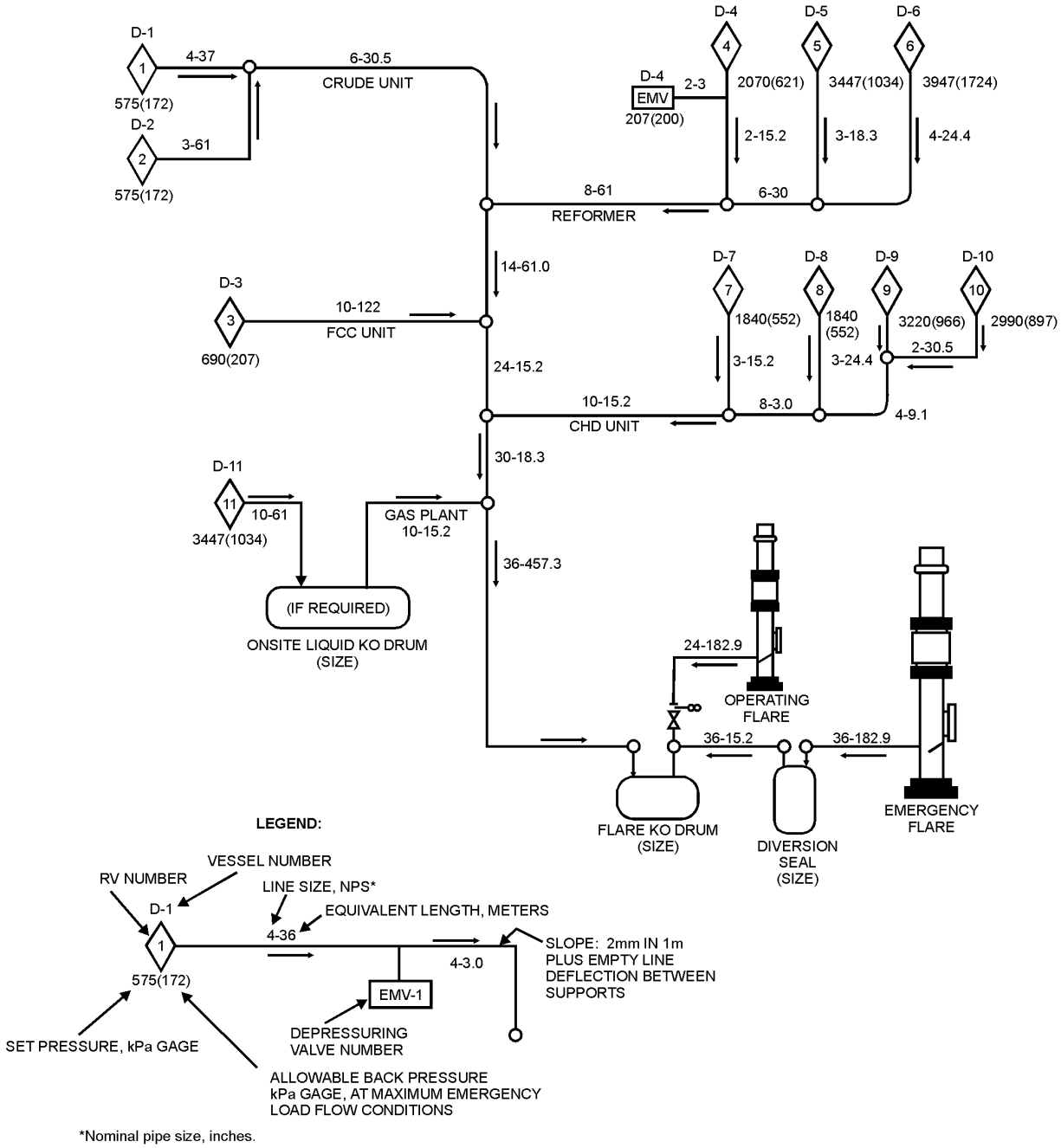

Figure 10: Closed Pressure Relief System and Flare–Typical Single-Line Diagram–SI (Metric) Units

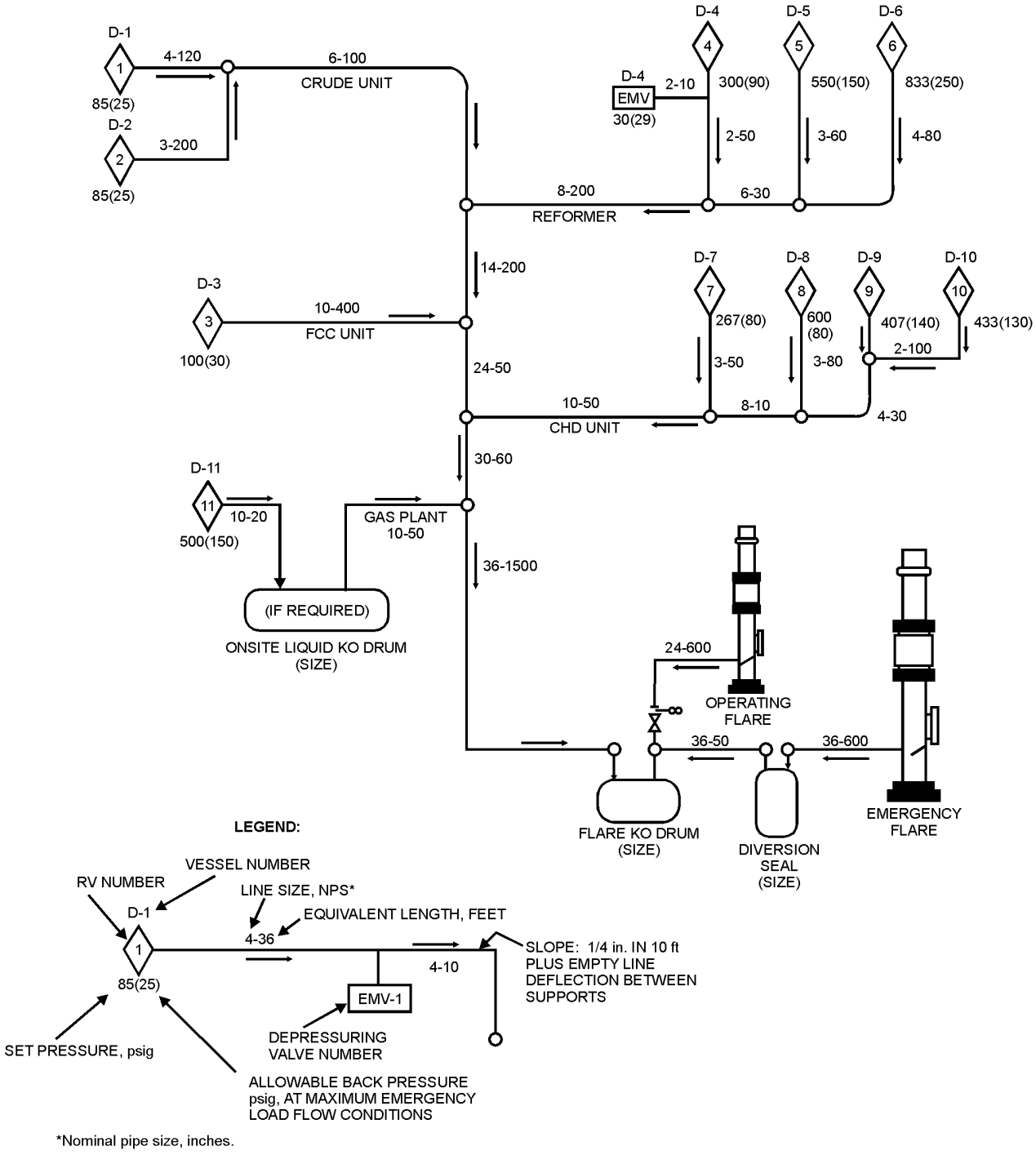

Figure 11: Closed Pressure Relief System and Flare–Typical Single-Line Diagram–Customary Units

Appendix A: Load Analysis

1. Scope

An analysis of the causes of discharge from the pressure relief valves that protect equipment, either individually or in groups, helps to define the critical areas in process units. Major sources of flare loads are thoroughly analyzed herein. However, sources that do not significantly affect the total load do not require detailed analysis.

2. General

2.1. Flare Load Design

For closed pressure relief systems, flare load design is based on the total load from all contributors to the single failure under consideration, rather than on the total load from all pressure relief devices.

2.2. Evaluation

Proper evaluation of simultaneous loads, which result from the single failures used to determine major flare loads, requires considerable judgment, experience and a thorough knowledge of the operations and equipment involved.

2.3. Causes of Discharge

The most common causes of pressure relief valve discharges that affect more than one process unit in an installation are:

- Loss of cooling water
- Total or partial power failure
- Loss of steam

2.4. Factors Affecting Emergency Relief Load

To establish the maximum emergency pressure relief load, factors to be considered are:

1. Layout of cooling water piping: this determines whether complete loss of cooling water to all process units will occur.
2. Types of drivers on cooling water pumps: standby drivers may be turbine driven or motor driven.
3. Use of air coolers: natural convection provides cooling when fans fail (see Section 4.2 in Appendix A).
4. Use of steam-driven pumps or compressors or both, that remain in operation during power failure.
5. Type of drive used on heat removal pumps or reflux pumps.
6. Use of proper instrumentation to keep heat removal circuits in operation during the emergency.

NOTE: Do not consider cases that result from double jeopardy, that is, two distinct events that are unlikely to happen simultaneously, such as a fire and a power outage. Multiple events with a common cause shall be considered.

2.5. Two-Phase Flow

A pressure relief valve handling a liquid at vapor/liquid equilibrium or a homogeneous mixed-phase fluid will produce flashing with vapor generation as the fluid moves through the valve. In these cases, two phase flow may occur. Special calculations are required for sizing PSVs handling two phase flow. Recommended procedures for these calculations are contained in Section 4.7 of API RP 520 PT I.

3. Heat Input

3.1. Effect on System

In general, heat input causes vapor generation and, in turn, increases pressure. This results in pressure relief valve discharge.

3.2. Methods

Basic heat input methods common to most process units use:

- Fired heaters
- Heat exchangers
- Reactor systems

3.3. Fired Heaters

- Uses: The bulk of heat input for installation processes is provided by fired heaters. These heaters, which are used for heat load services, include crude preheaters, reformer preheaters, coking heaters and large column reboilers.
- Heat Input to Equipment: To stop the heat input to equipment that is downstream of a fired heater, the fuel flow shall be shut off. Where the oil charge is heavy and easy to crack, coke may form in the heater tubes and prevent the complete shutoff of feed. Therefore, the oil charge shall be continued at a reduced rate or steam shall be injected into the heater tubes to purge the oil. In either event, after the burners are shut off, the heat input to the equipment that is downstream of the heater shall continue at a reduced rate until one of the following occur:
  - The oil or steam flow stops
  - The temperature of the fired heater drops to the oil or steam inlet temperature

3.4. Heat Exchangers

3.4.1. Heating Media

Heating media for two principal types of heat exchangers used for heat input in process units are:

3.4.1.1. Steam

When steam is used as the heating medium, the continuation of heat input means a net heat input to the overall process unit. To stop the heat input, either the steam or the flow of material being heated shall be shut off. With no automatic action, it shall be assumed that the heat input will continue at the normal rate until the material being heated is depleted. Following is a simplified example of the use of steam.

A steam preheater heats a column feed that comes from a surge drum. The preheater continues heat input until the level control on the surge drum shuts off. Assume that feed continues at the normal rate until the volume between the top and bottom level control taps is depleted. For steam-heated reboilers, compute the liquid holdup and composition in the column to establish feed duration. Again, assume normal reboil rate during this time.

3.4.1.2. Hydrocarbons

Heat exchangers that use hydrocarbons from another section of the same unit as a heating medium merely transfer heat from one section to the other. For example, a debutanizer column reboiler may be heated by a heavy gas oil (HGO) intermediate stream from a fluid catalytic cracking (FCC) main fractionator. The heat input to the debutanizer increases the flare load from the gas plant and the load from the main fractionator decreases.

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3.4.2. Limiting Heat Input

The duration and rate of heat input for heat exchangers may be limited by either the heating medium or the material being heated and both shall be checked. Plug flow of the heating medium inventory is assumed in closed systems. After the initial inventory is depleted, the heat input rate shall be adjusted for the change in temperature of the heating medium.

3.4.3. Operating vs Set Pressure

When the heat exchanger input method is used, the difference between the normal operating pressure of a system and the set pressure of the pressure relief valves shall be determined. In some cases, this difference is large and therefore the heat input rate for a reboiler at relieving pressure and temperature may change significantly from the heat input rate at operating pressure and temperature. The heat input rate shall be adjusted for this effect if the system is a major contributor to the flare load.

3.5. Reactor Systems

Reactor systems may be divided into two general groups:

- Those that require heat (endothermic)
- Those that release heat (exothermic)

These systems contain large heat sinks that can continue to supply heat input when the primary source of heat is shut off. Examples of reactor systems are coke drums, hydrocrackers and FCC reactors.

3.5.1. Endothermic Systems

Catalytic cracking, coking and reforming systems are examples of endothermic types of reactor systems. Although endothermic reactions require heat from the reactor system, they result in an increase in volume and pressure, which requires pressure relief. The rate of vapor generation depends on the feedrate to the system and the mass of the heat sink. Cases to consider are:

3.5.1.1. System Feed Shutoff

When the system feed is shut off, the rate of vapor generation usually is low and can be neglected in establishing flare loads.

3.5.1.2. Continuing System Feed

When the system feed stream continues, vapor generation is computed by assuming that the heat of reaction is removed from the mass of the system and that the reaction rate varies with the system temperature. In cases where the heat of reaction is supplied by the incoming hot catalyst, it is assumed

that the vapor generated is directly proportional to the feed rate; that is, the source of heat to the system does not decay with time.

3.5.1.3. Reforming Systems

In cases where the fresh feed is shut off but the recycle gas flow continues, the time and rate of heat input (based on the time to purge the system of reactants) shall be computed.

3.5.2. Exothermic Systems

The exothermic type of reaction results in a decrease of moles in the system and a rise in system temperature. Hydrocracking, hydrotreating, polymerization and alkylation are examples of exothermic types.

Pressure changes are calculated in the same manner as in the endothermic system. Note, however, that as the reaction continues, the released system heat tends to increase pressure while the decrease in moles tends to decrease pressure. In general, the controlling variable is the vapor generation and not the temperature level. Thus, while endothermic reactors tend to increase in pressure, exothermic reactors tend to decrease in pressure.

3.6. Compressors

- Uses: Compressors may be used for refrigeration systems, reinjection, recycle compression and booster compression.
- Cryogenic Systems: When a refrigeration compressor trips, the refrigeration system warms up and the pressure increases. Designing the refrigeration system for the maximum pressure (when the compressor is down and the system has equalized) shall be considered. The remaining parts of the system will also warm up quickly and will require emergency relief. The compressor trip may be interlocked with blocking of the system feed to minimize flaring. If this is done, valve closure time becomes critical. Valve operators (air, hydraulic or motor) shall be considered carefully.

3.7. High-Pressure Ethylene Systems

Special consideration shall be given to relief of systems and equipment handling ethylene at high pressure (>4350 psig [>300 bar]).

4. Heat Removal

4.1. Basic Methods

Some basic methods of consuming heat input to a given system are:

- Use of air and water exchangers to completely remove heat
- Use of heat exchangers to transfer heat to other systems
- Raising the heat content of the system to absorb heat by such factors as quantity and temperature of the oil inventory
- Vapor generation to absorb heat by increasing system pressure

4.2. Air and Water Exchangers

4.2.1. Air Coolers and Condensers

In cases of fan failure, it shall be assumed that 10 percent of design duty can be maintained through natural convection on forced draft air coolers. With induced draft air coolers, 25 percent of the design duty may be assumed. Higher percentages of natural convection may be available on induced draft air coolers and shall be calculated in accordance with the AIR PFR computer program (MRCTEC).

4.2.2. Water Coolers and Condensers

It is assumed that water coolers and condensers maintain a duty proportional to the cooling water circulation rate. For total loss of circulating water, the exchangers are assumed to have no heat removal capacity. Some decay time will occur on loss of circulating water while the water in the exchangers is heated to hotside temperatures. Normally, this decay is not taken into account and is assumed to be negligible. The decay time shall be checked in exchangers that have large water volumes or in which steam will be generated.

4.2.3. Overhead Condensers

The overhead condenser is the most critical service for both air and water exchangers. When part of the overhead heat removal capacity is lost, the new exit vapor-liquid composition and temperature are estimated from the condensing curve. This is particularly important in columns with overhead material of a wide boiling range, such as crude columns, FCC main fractionators and coker fractionators.

4.2.4. Liquid Filled Air Coolers

The relief rate for fire exposure of liquid filled air coolers shall be based on a spill fire under or adjacent to the air cooler. The fire area is based on the drainage system layout (typically 3,000 ft^2). Assume that 100 percent of the surface area of all rows of tubes (without fins) is exposed to the fire, whether or not the fans are in operation. If the exchangers are located under the high point of the drainage area, with adequate equipment spacing and no fire potential equipment located under the coolers, consideration could be given to reducing the tube surface area assumed to be exposed to fire to no less than 50 percent of the surface area of all rows of tubes (without fins).

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4.3. Heat Exchangers

The heat exchanger method covered in Section 3.4 of Appendix A is applicable here. Heat transfer circuits are merely a means of transferring heat from one section of the system to another. As an example, consider an FCC reactor system in which the debutanizer is reboiled with an HGO stream from the main fractionator. When a failure occurs, the total feed to the FCC reactor stops and, thus, the heat input to the main fractionator stops. If the debutanizer reboiler circuit continues, the level of the oil in the main fractionator is substantially decreased and the heat is used to generate a flare load in the debutanizer. If, however, the debutanizer reboiler circuit is stopped, neither the main fractionator nor the debutanizer relieves to the flare.

The action of all heat transfer circuits on the occurrence of a failure shall be carefully considered to minimize the total release from the system.

5. Heat Content of System

5.1. Analysis

Not all the heat input to a system goes to vapor generation. When a system is analyzed for flare loads, a part of the heat and material input can and, normally, does remain in the system. This can best be illustrated by an example of heat content.

Assume a column is being fed from a surge drum through a steam preheater. The preheater heats the feed from 38–121°C (100–250°F). At tower conditions, the feed flashes to 30 percent by weight vapor. If all streams to and from the tower (except the feed) were to stop, only the incoming vapor or an equivalent number of moles will have to be condensed to prevent pressure buildup. The heat associated with the liquid portion of the feed remains in the system.

This concept is important in analyzing large columns, such as crude columns and FCC main fractionators, where the heat input is supplied by vaporized feed. The approach to this type of system is as follows:

1. Flash the incoming feed at the expected flash conditions to determine the vapor feed to the column.
2. Assume the product fractions of the feed are condensed at the draw temperature of the column. Light fractions that boil at a lower temperature than the top temperature are assumed to go overhead as vapor.
3. Determine the enthalpy difference between the incoming vapor and the condensed fractions. This represents the portion of heat to be removed by vaporization of column inventory or heat exchanger circuits. The balance of heat is used to heat the system.

4. Repeat this procedure for small increments of time, taking into account the increase in system temperature and pressure levels. The time increments will depend on heat input rate, duration and liquid inventory in the system.

5.2. Vapor Removal

The net vapor generation within a given system, after all methods of heat removal have been considered, will cause the pressure to increase. Vapors may be removed from the system by any of the following methods:

- Compressors that continue to operate
- Pressure control valves that vent to other units, to the fuel gas system or to the flare
- Pressure relief valves that relieve to the flare or to the atmosphere

In addition, the system itself shall have a capacity to absorb vapors while increasing pressure to the various set pressures of the relieving elements. For large systems, this surge capacity can be a substantial aid in reducing peak flare loads and shall be computed.

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Appendix B: Protection of Catalyst-Filled Reactors

1. General

Most pressure vessel codes and regulations require that a vessel be protected against equipment overpressure by positive-action, code-approved protective devices. Overpressure is considered as a pressure greater than the maximum allowable working pressure, which is generally the design pressure that is stamped on the vessel nameplate. Pressure relief valves are provided to protect an individual vessel or a system of vessels.

2. Flow Resistance

Catalyst-filled reactors usually are protected by a pressure relief valve on a gas-liquid separator downstream of the reactor. This is a viable system, provided that no appreciable flow resistance arises between the reactor inlet and the separator.

Flow resistance could build up due to:

- Plugging of the catalyst bed
- Fluid distribution or collection devices
- Piping between reactor and separator

Experience has shown that whenever a buildup of flow resistance occurs it takes place over time periods longer than the commonly accepted time period of 10–30 minutes, provided for operator response to an abnormal condition. Therefore, high-pressure alarms shall be placed upstream of the reactors to alert the operators to take appropriate action when the pressure at this point becomes hazardous.

3. Special Pressure Relief Devices

To provide structural reliability in the unlikely event of failure of operator response or complete failure of all alarms or other types of protective devices, the reactor vessels shall be designed for a pressure not less than 83 percent of the maximum source pressure.

- When the reactors are designed for less than 83 percent of the maximum source pressure, additional special pressure relief devices are required. Each case shall be considered individually.
- In some instances, although reactors have been designed for pressures above 83 percent of the source pressure, additional special pressure relief devices shall be required when they are subject to exothermic reactions.

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Appendix C: Dynamic Pressure Relief System Analysis

A dynamic pressure relief system analysis is conducted by building an engineering grade dynamic model of a tower as well as associated controls, pumps, drums, reboilers, condensers, pressure relief valves, etc. Flare loads are then computed by imposing the same upsets on the model, which will cause flaring in the plant (e.g., loss of power causing loss of pumps and loss of fin-fan motors).

The results obtained are more realistic than those obtained via classical steady state design methods in two ways. First, the dynamic analysis results more accurately reflects the sequence and duration of relief from pressure relief devices. For example, the dynamic analysis of multiple PSVs on a tower show when each PSV lifts, how long it stays open and its associated flare flow. Historically, these studies have found that PSVs do not lift simultaneously and the peak load is invariably significantly less than the sum of all of the PSV flowrates.

In addition, a dynamic model eliminates "double counting." When a PSV removes material from several interconnected vessels, other PSVs may not lift due to reduced inventory.

Appendix D: Flare Sizing Calculations

1. Flare Stack Height

Flare stack height, which is usually determined by allowable radiant heat intensities at grade, shall be calculated in accordance with the procedure given in Item 2 below. Flare stack height so calculated shall also be checked to ensure that the sulfur dioxide (SO_2) ground level concentration, that is produced from burning H_2S, does not exceed local, state or federal air pollution restrictions. Requirements for flare stack height are as follows:

1. Elevated flare stacks may be guyed, self-supporting or supported by a derrick structure, depending on space availability and height of the stack. Ladders and platforms are not required on self-supporting stacks that can be lowered for maintenance.

2. For a system with a single flare, the height of the flare stack shall be determined using FvSIM software. The GKN Birwelco three-point model for estimating flame radiation intensity shall be used. The maximum allowable radiation intensity levels shall be in accordance with Table D–1.

3. Continuous gas discharge at rates significantly below maximum emergency relief, but above the normal continuous leakage and purge rates for pressure relief valves, will result in premature flare tip burnout. Installation of two flares is recommended: an operating flare for smokeless burning of day-to-day releases and a separate emergency flare for burning of infrequent emergency releases. The two flares shall be connected through a water diversion seal, which will allow flow to the emergency flare as backpressure builds up in the operating flare (see Figure D–1). Pressure drop considerations shall govern the relative sizes of the tips, but the operating flare tip is generally equal to or slightly smaller than the emergency tip.

   When the relative relief rates are established, the sizing procedure given in Section 1.2 of Appendix D shall be used for each flare. The radiant heat loads at each point shall be the sum of the expected heats from both flares.

4. Flare stack height can also be governed by dispersion.

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Table D–1: Allowable Radiant Heat Intensities in W/M^2 ($Btu/Hr/Ft^2$) Excluding Solar Radiation

		In Plant		Public
		Appropriate Clothing*	**w/o Appropriate Clothing***	
Continuous Release		1105 (350)	790 (250)	790 (250)
Emergency Releases	Travel time to shelter:			
	6 sec	9465 (3000)	3150 (1000)	
	1 min	6300 (2000)	3150 (1000)	
	3 min	4730 (1500)	1580 (500)	1580 (500)
	No shelter available	1580 (500)	790 (250)	790 (250)
	Equipment exposure only	15,770 (5000)		
	Volatile liquids tanks, API separator, CCB	2365 (750)		NA

***Definition:** Appropriate clothing is clothing such as coveralls, long sleeved shirts, pants, hard hat, etc. which can shield all body areas except for the face and hands from exposure to flare radiant heat.

2. Flare Tip

The minimum diameter for pipe tips shall be based on a velocity of 0.5 Mach or as recommended by the manufacturer. The velocity for proprietary tips shall be recommended by the manufacturer. The equation for sonic velocity (one Mach) is as follows for an ideal gas:

$$V_s = C\sqrt{\frac{kT}{M}}$$

Where:

V_s = sonic velocity, m/s (ft/s)

C = 89, SI units (223, customary units)

k = specific heat ratio, C_p/C_v

T = absolute gas temperature at the tip, °K (°R)

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M = molecular weight

Tips shall be fitted with a flame retention device that is rated by the vendor at 0.5 Mach or higher. Tips shall also have windshields to reduce flame lick at low flaring rates. Depending on the gas being flared, the tip and/or windshields may have to be constructed of high-temperature corrosion-resistant alloys, such as Inconel 625 or Incoloy 800, to avoid maintenance problems. Normal materials of construction are heat-resistant stainless steels, such as Type 309 or Type 310.

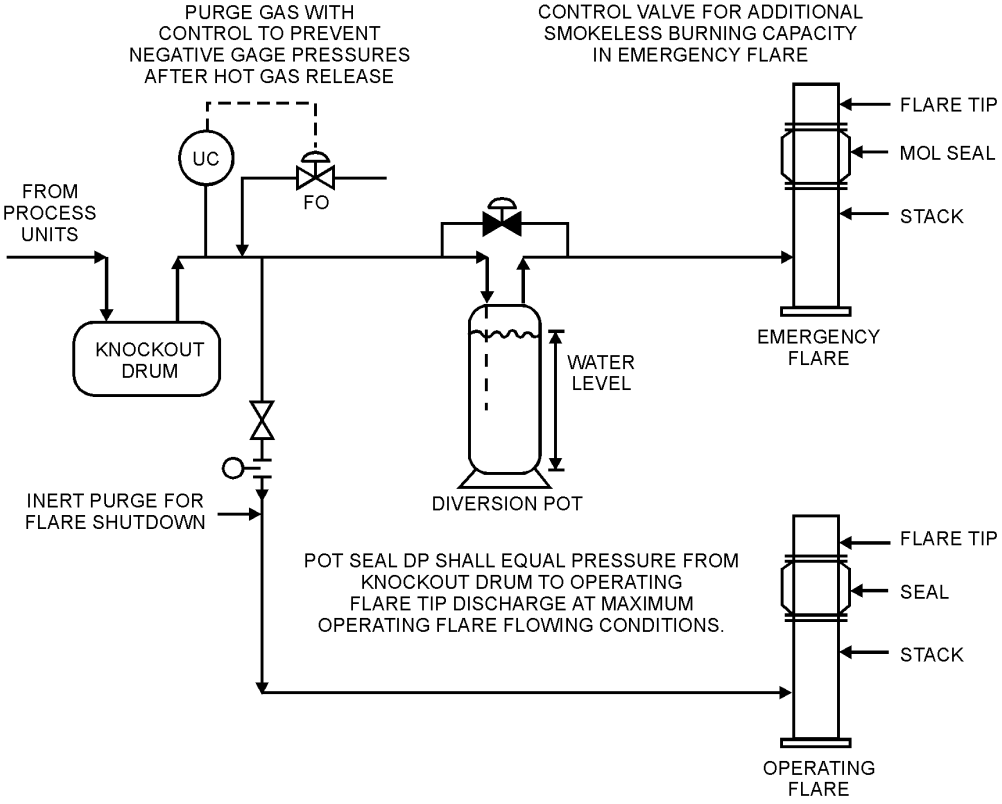
PURGE GAS WITH CONTROL TO PREVENT NEGATIVE GAGE PRESSURES AFTER HOT GAS RELEASE
CONTROL VALVE FOR ADDITIONAL SMOKELESS BURNING CAPACITY IN EMERGENCY FLARE
UC
FO
FROM PROCESS UNITS
FLARE TIP
MOL SEAL
STACK
KNOCKOUT DRUM
WATER LEVEL
EMERGENCY FLARE
INERT PURGE FOR FLARE SHUTDOWN
DIVERSION POT
POT SEAL DP SHALL EQUAL PRESSURE FROM KNOCKOUT DRUM TO OPERATING FLARE TIP DISCHARGE AT MAXIMUM OPERATING FLARE FLOWING CONDITIONS.
FLARE TIP
SEAL
STACK
OPERATING FLARE

Figure D–1: Installation of an Operating Flare and an Emergency Flare

Relief Valves and Rupture Disks

EPT 05-T-08

December 1992 Draft

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Table of Contents

1. Scope 6

2. References 6

2.1. MEPS–Mobil Engineering Practices 6

2.2. Mobil Tutorials 6

2.3. API–American Petroleum Institute 6

2.4. ASME–American Society of Mechanical Engineers 7

3. Code Requirements for Pressure Relief 7

4. Types of Pressure Relief Devices 7

4.1. Relief Valves 7

4.2. Safety Valves 8

4.3. Safety Relief Valves 8

4.4. Rupture Disks 8

5. Types of Pressure Relief Valves 8

5.1. Conventional 9

5.2. Balanced Bellows 11

5.3. Pilot-Operated 13

6. Rupture Disks 17

6.1. 17

6.2. 20

6.3. 20

6.4. 20

6.5. 20

7. Pressure Relief Valve Sizing 22

7.1. General 22
7.2. Gas or Vapor Service 24
7.3. Steam Service 38
7.4. Liquid Service 39
7.5. Two-Phase Flow 43
7.6. Effects of Back-pressure on Capacity 44
7.7. Installation 44
7.8. Rupture Disk Sizing 46
Appendix A–Nomenclature 48
Appendix B–Example Problems - Metric Units 50
1. Two-Phase Flow 50
2. Two-Phase Flow 50
3. Conventional Safety Relief Valve (Vented Bonnet) 51
4. Calculate Orifice Size for Gas 51
5. Calculate Orifice Size for Liquid 52
6. Calculate Total Orifice Size 52
7. Balanced Bellows Safety Relief Valve 53
8. Calculate Orifice Size for Gas 53
9. Calculate Orifice Size for Liquid 54
10. Calculate Total Orifice Size 54
11. Pilot Operated Valve 55
12. Calculate Orifice Size for Gas 55
13. Calculate Orifice Size for Liquid 55
14. Calculate Total Orifice Size 56
15. Gas Subcritical Flow 56

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16. Subcritical Flow Example Problem....56
17. Conventional Safety Relief Valve (Vented Bonnet)....57
18. Balanced Bellows Safety Relief Valve....58
19. Pilot Operated Valve....58
Appendix C–Example Problems - Customary Units....59
20. Two-Phase Flow....59
21. Two-Phase Flow Example Problem....59
22. Conventional Safety Relief Valve (Vented Bonnet)....61
23. Calculate Orifice Size for Gas....61
24. Calculate Orifice Size for Liquid....62
25. Calculate Total Orifice Size....62
26. Balanced Bellows Safety Relief Valve....63
27. Calculate Orifice Size for Gas....63
28. Calculate Orifice Size for Liquid....64
29. Calculate Total Orifice Size....64
30. Pilot Operated Valve....65
31. Calculate Orifice Size for Gas....65
32. Calculate Orifice Size for Liquid....65
33. Calculate Total Orifice Size....66
34. Gas Subcritical Flow....66
35. Subcritical Flow Example Problem....66
36. Conventional Safety Relief Valve (Vented Bonnet)....67
37. Balanced Bellows Safety Relief Valve....68
38. Pilot Operated Valve....68

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Table of Figures

Figure 1: Cross Section of a Conventional Relief Valve (Courtesy of API).....9

Figure 2: Schematic Showing Operation of Conventional Relief Valves (Courtesy of API, API RP 520 I).....10

Figure 3: Cross Section of a Balanced Bellows Relief Valve (Courtesy of API).....12

Figure 4: Schematic Showing Operation of a Balanced Bellows Relief Valve (Courtesy of API, from API RP 520 I).....13

Figure 5: Cross Section of a Pilot Operated Relief Valve 15

Figure 6: Pilot Operated Valve Backflow Protection by Means of Check Valves 17

Figure 7: Conventional Rupture Disk (Courtesy of API, from API RP 520 I) 18

Figure 8: Pressure Level Relationships for Rupture Disk Devices (Courtesy of API, from API RP 520 I).....19

Figure 9: Scored Tension–Loaded Rupture Disk (Courtesy of API, from API RP 520 I)21

Figure 10: Pressure Level Relationships for Pressure Relief Valve (Courtesy of API, from API RP 520 I).....23

Figure 11: Specific Heats Ratio Versus Molecular Weight for Hydrocarbon Gases (Courtesy of API, from API RP 520 I).....28

Figure 12: Coefficient C Versus Specific Heats Ratio (Courtesy of API, from API RP 520 I).....31

Figure 13: Variable or Constant Back-Pressure Sizing Factor, K_b, for Balanced Bellows Safety Relief Valves (Vapors and Gases) (Courtesy of API, from API RP 520 I).....33

Figure 14: Values of Subcritical Flow Coefficient F_2 (Courtesy of API, from API RP 520 I).....37

Figure 15: Correction Factor Due to Back-Pressure on Balanced Bellows Pressure Relief Valves in Liquid Service (Courtesy of API, from API RP 520 I) 41

Figure 16: Capacity Correction Factor Due to Viscosity (Courtesy of API, from API RP 520 I).....43

1. Scope

Oil and gas production facilities handle gas and liquids under pressure conditions where the improper use or failure of certain components may cause an overpressure of various facility components. Economic considerations do not allow the facility engineer to design all components to withstand the maximum pressure to which they may be exposed. To provide a safe yet economic design, pressure relieving devices are used.

This tutorial deals with the design, selection, operation, and maintenance of pressure relief devices for the protection of pipe, valves, fittings, vessels, and other components. Pressure safety valves and rupture disks are discussed, along with a variety of installation methods and testing techniques. Downstream gas disposal methods are discussed in the tutorial EPT 04-T-02 on Flare and Vent Systems. Most definitions required for an understanding of pressure relieving devices can be found in Part 1 of API RP 520 I.

2. References

The following Mobil guides and industry publications shall be considered a part of this EPT. Refer to the latest editions unless otherwise specified herein.

2.1. MEPS–Mobil Engineering Practices

MP 70-P-06	Pressure Relief and Vapor Depressuring Systems

2.2. Mobil Tutorials

EPT 04-T-02	Flare and Vent Systems
EPT 07-T-03A	Reciprocating Compressors
EPT 07-T-03B	Reciprocating Compressors
EPT 09-T-01	Facilities Piping

2.3. API–American Petroleum Institute

API RP 14C	Recommended Practice for Analysis, Design, Installation, and Testing of Basic Surface Safety Systems for Offshore Production Platforms Fifth Edition; Errata - 1994
API RP 14E	Recommended Practice for Design and Installation of Offshore Production

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	Platform Piping Systems Fifth Edition
API RP 520 I	Sizing, Selection and Installation of Pressure-Relieving Devices in Refineries, Part I - Sizing and Selection
API RP 521	Guide for Pressure-Relieving and Depressuring Systems Fourth Edition

2.4. ASME–American Society of Mechanical Engineers

ASME SEC VIII D1	SISI Units (Boiler and Pressure Vessel Codes)

3. Code Requirements for Pressure Relief

There are five primary codes which address the use of pressure relieving components. The pressure vessel code, whether American, Canadian, or British, requires the presence of a relief device on all code approved vessels. The American Petroleum Institute (API) provides API RP 520 I, “Sizing, Selection, and Installation of Pressure Relieving Devices in Refineries”. This RP is often applied to production facilities and provides a guide for sizing and analysis of safety relief devices. API RP 14C, “Analysis, Design, Installation and Testing of Basic Surface Safety Systems for Offshore Production Platforms”, recommends the installation of relief valves for various components within a production system. API RP 14E, “Design and Installation of Offshore Production Platform Piping Systems”, discusses the use, in conjunction with API RP 14C, of pressure relieving devices to protect piping systems. Finally API RP 521, “Guide for Pressure-Relieving and Depressuring Systems”, discusses design of the overall relieving system. Piping systems are covered in the tutorial EPT 09-T-01 on Facilities Piping, while relieving systems are covered in the tutorial EPT 04-T-02 on Flare and Vent Systems.

4. Types of Pressure Relief Devices

All of the following devices relieve pressure automatically, actuated by upstream static pressure.

4.1. Relief Valves

4.1.1.

Relief valves are spring loaded pressure relief devices. At the set pressure, the inlet pressure force overcomes the spring force and the valve disk begins to lift off the seat. As inlet pressure increases, the lift of the disk increases proportionally to allow an increase in the flow. The closing pressure is less than the set pressure and shall be reached after the blowdown phase is complete.

4.1.2.

These devices are used primarily for liquid service (incompressible fluids) and open in proportion to increasing pressure over opening pressure. Relief capacities are usually rated at 10 or 25 percent overpressure, depending on the application.

4.2. Safety Valves

Safety valves are also spring loaded pressure relief devices, but they are designed to provide full opening with minimum overpressure. Static pressure and the kinetic energy of the gas or vapor are utilized to overcome the spring force on the disk as it lifts, resulting in a popping action. These devices are used primarily for steam and air services (compressible fluids) and provide rapid full opening or pop action with little overpressure.

4.3. Safety Relief Valves

4.3.1.

Safety relief valves provide the characteristics of safety valves in gas or vapor service and the characteristics of relief valves in liquid service.

4.3.2.

They may be pilot operated - controlled by an auxiliary (pilot) valve - or spring loaded. Spring loaded safety relief valves are of either of two types, conventional (performance depends on back-pressure) or balanced (minimizes the effect of back-pressure).

4.4. Rupture Disks

Rupture disks are non-reclosing differential pressure relief devices. A “rupture disk device” is defined as both the rupture disk itself and the rupture disk holder.

5. Types of Pressure Relief Valves

Valves that activate automatically to relieve pressure are called “safety valves”, “relief valves”, or “safety relief valves”. Safety valves are spring loaded and characterized by a rapid full opening or “pop” action. They are used primarily for steam or air service. Sometimes they are referred to as “pop valves”. Relief valves are spring loaded and open more slowly. They reach full opening at 10 or 25 percent above set pressure and are used primarily for liquid services. Safety relief valves can be either spring loaded or pilot operated. Most automatically actuating relief devices used in production facilities are actually safety relief valves; however, they are commonly referred to as relief valves or

safety valves. In this tutorial the term “relief valve” is used in the generic sense of any automatically actuating pressure relieving device with reclosing capabilities. There are three types of relief valves: conventional (spring loaded), balanced bellows, and pilot operated.

5.1. Conventional

5.1.1.

Figure 1 shows a cross section of a conventional relief valve, while Figure 2 is a schematic that shows the valve's operation. A vented bonnet configuration is one that consists of a spring which creates a closing force that overcomes both the pressure in the vessel, P_1, and the back-pressure downstream of the valve, P_2. At the set point, the force of P_1 and P_2 acting on their respective areas equals the spring force, and the valve opens. If the valve is installed in a header system with other valves, then the set point required to overcome the spring force decreases if P_2 is increased.

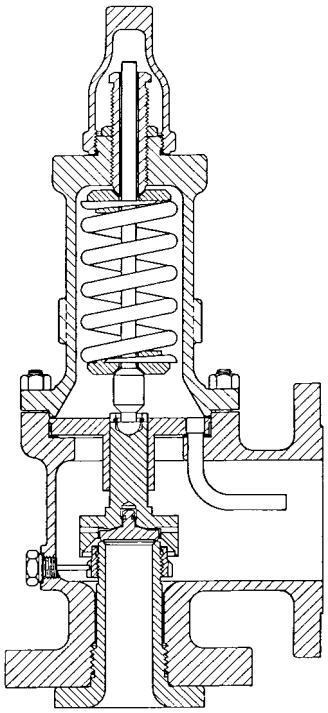

Figure 1: Cross Section of a Conventional Relief Valve (Courtesy of API)

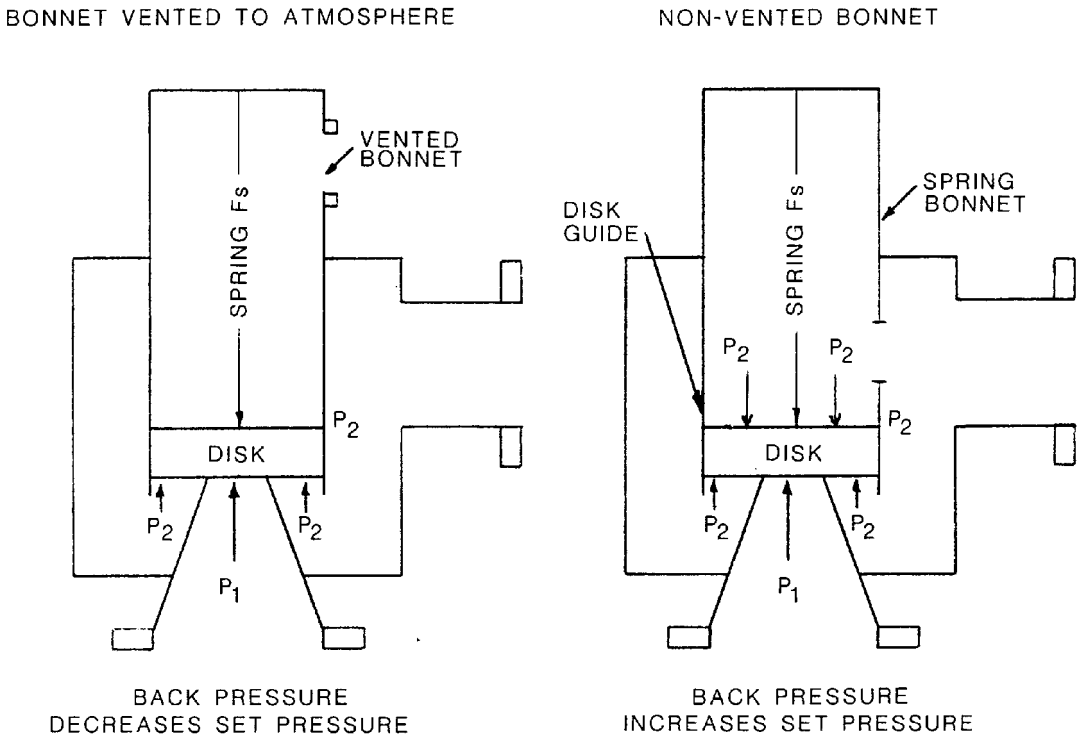

Figure 2: Schematic Showing Operation of Conventional Relief Valves (Courtesy of API, API RP 520 I)

5.1.2.

In a non-vented bonnet type conventional relief valve, the back-pressure acts downward on the entire disk area but also acts upward on a portion of the disk area. In this case, an increasing back-pressure shall cause an increase in the valve set point.

5.1.3.

Where the discharge is routed independently to atmosphere, conventional relief valves shall be used. If this type of device is installed in a header system, when one device is relieving, thereby creating a header back-pressure, the set point of every other device in the header system shall be affected. Conventional relief valves are normally used in an open system or in a closed flare header system designed so that the back-pressure does not exceed 10 percent of the relief valve set pressure.

5.1.4.

Conventional relief valves may be equipped with lifting levers or screwed caps. The lifting lever permits mechanical operation of the valve for testing

or cleaning out foreign material from under the seat. Screwed caps prevent leakage from the valve, but they also prevent overriding the spring if foreign material or ice becomes lodged under the disk. Relief valves for steam and air service are required by code to be furnished with lifting levers.

5.2. Balanced Bellows

5.2.1.

Balanced bellows relief valves are a variation of spring-loaded valves. They contain a bellows arrangement to prevent back-pressure from affecting the set point. Figure 3 shows a cross section of a balanced relief valve, and Figure 4 is a schematic that shows how the valve operates. The bonnet is vented to atmosphere, providing a constant force downward on the disk. The bellows is installed in such a manner that the back-pressure acts both downward and upward on equal areas of the disk. This means that the forces created by the back- pressure cancel and therefore do not affect the set point.

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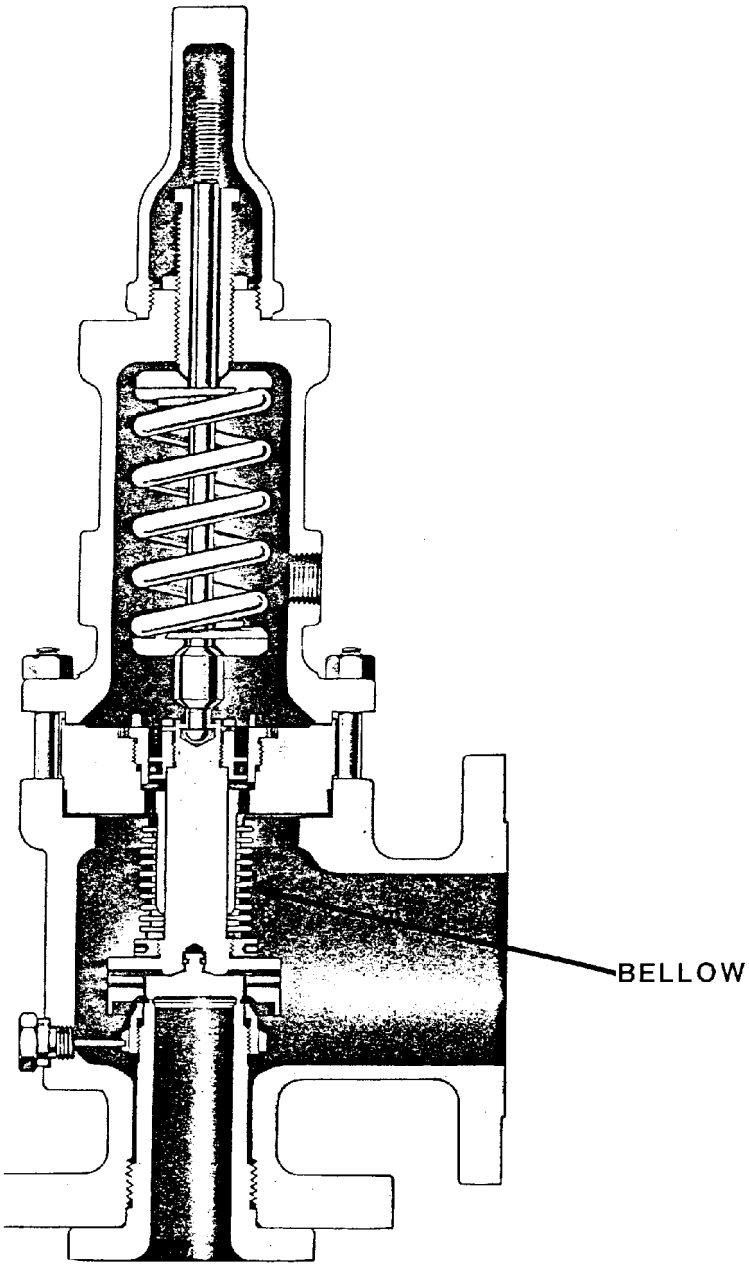

Figure 3: Cross Section of a Balanced Bellows Relief Valve (Courtesy of API)

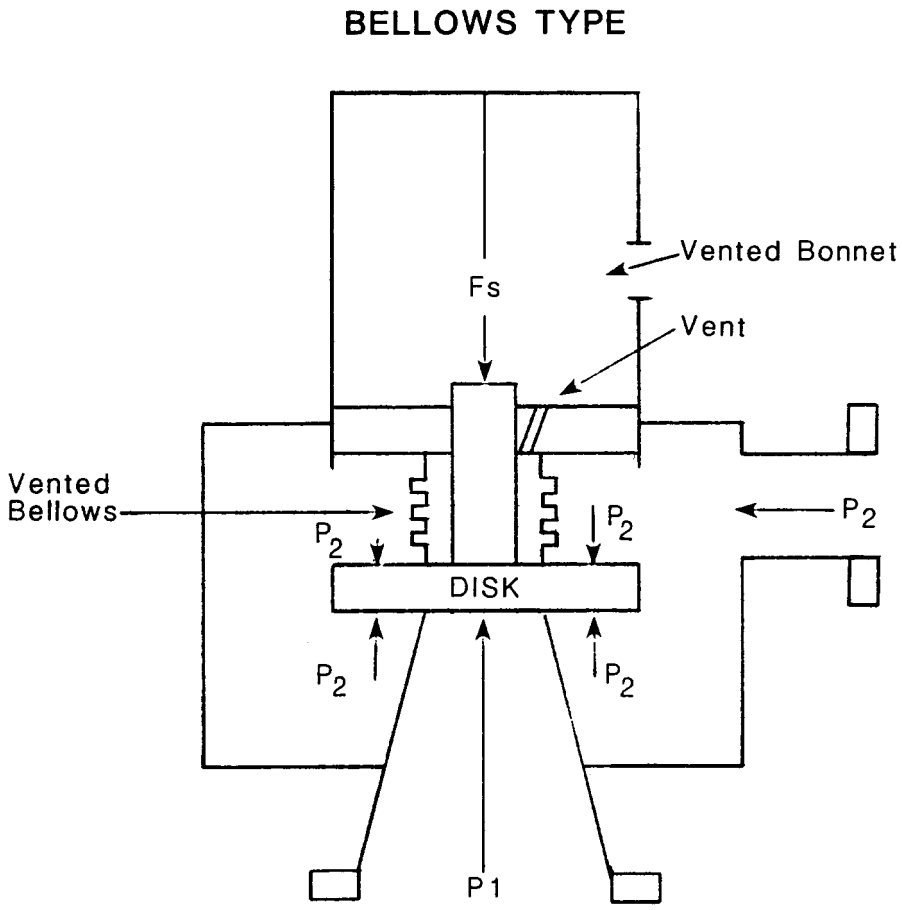

Figure 4: Schematic Showing Operation of a Balanced Bellows Relief Valve (Courtesy of API, from API RP 520 I)

5.2.2.

Balanced bellows valves are normally used where the relief valves are piped to a closed flare system and the back-pressure exceeds 10 percent of the set pressure. They cost more than conventional relief valves. In sour service, the bonnet vent shall be piped to a safe location.

5.3. Pilot-Operated

5.3.1.

There is no spring in a pilot operated relief valve. Instead a pilot valve, shown in Figure 5, senses vessel pressure. Under normal conditions, vessel pressure is routed through the pilot to the upper side of the disk. The area

exposed to this pressure is larger than the disk area exposed to the inlet nozzle. Therefore the seating force on the disk is greater than the lifting force. In fact, as the vessel pressure approaches the set point, the closing force increases to assure a tight seal and to prevent valve “chatter”. When the set point is reached, the pilot shifts, blocking the pressure from the vessel, venting pressure from above the disk, and allowing the disk to rise.

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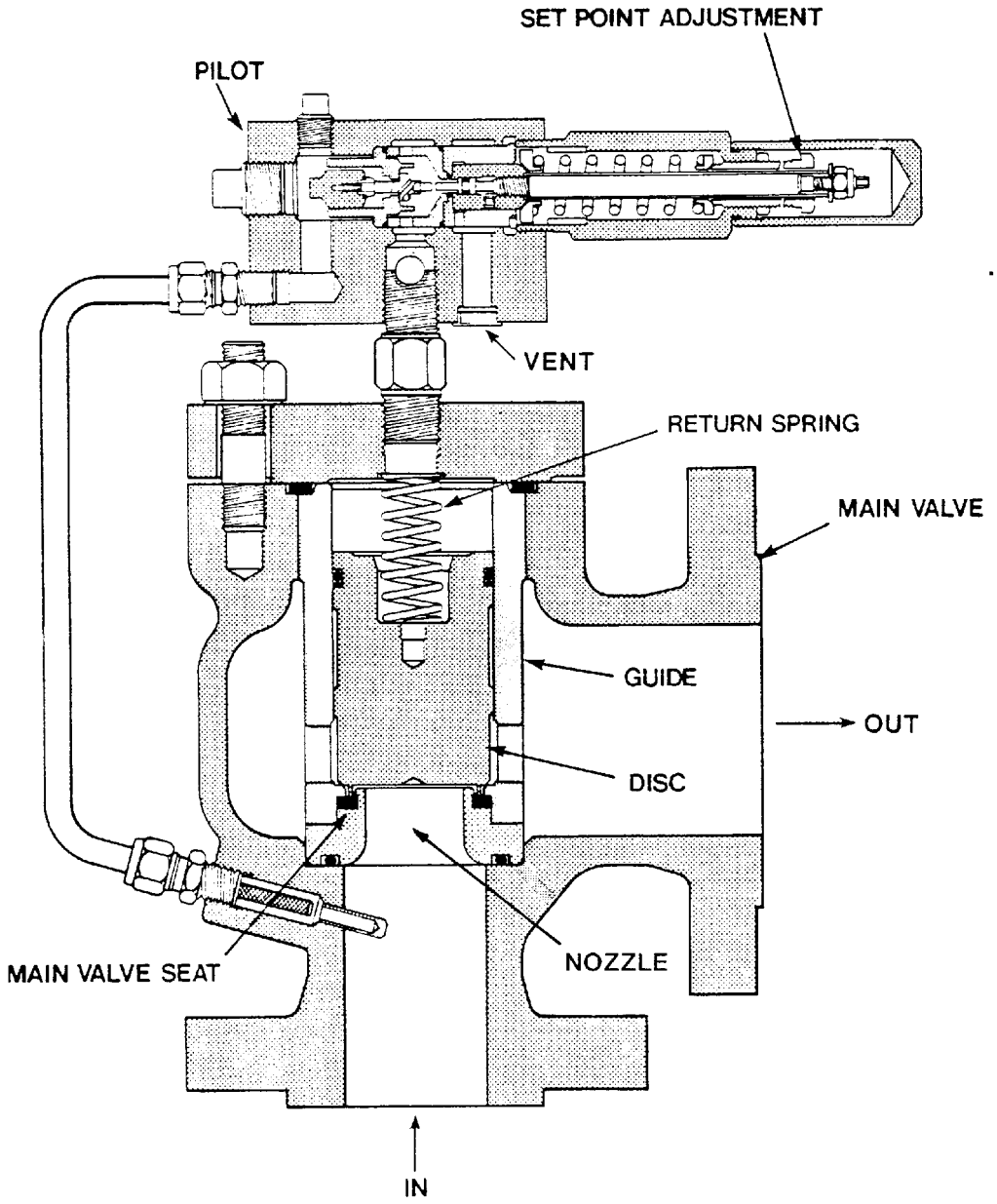

Figure 5: Cross Section of a Pilot Operated Relief Valve

5.3.2.

Pilot-operated valves have several advantages besides not allowing operation near the set point to cause chatter. The set point is not affected by back-pressure as the upper portion of the disk is isolated. With proper auxiliary valves in the pilot lines, the pilot may be tested without venting vessel

pressure. This may be useful if the vessel contains toxic materials. However, it shall be realized that corrosion between the disk and seat or other obstructions in the valve body may prevent the disk from lifting. Periodic bench testing may be required to assure the main valve will function properly.

5.3.3.

One disadvantage of pilot operated valves is that, if there is no pressure in the vessel, back-pressure on the valve could cause the disk to lift. If a vessel was shut-in and depressured for maintenance, and the relief valve outlet was tied into a relief header, when another valve in the header was opened, back-pressure would be applied to the disk. Figure 6 shows an arrangement of two check valves in the sensing system to assure that either vessel pressure or header pressure, whichever is greater, is always present above the disk. Such an arrangement provides “backflow protection”. Additionally, pilot operated valves shall not function if the pilot fails. If the sensing line fills with hydrates or solids, the valve shall not open until the vessel pressure is 25 percent greater than the pressure trapped above the disk (usually the normal operating pressure of the vessel). For this reason pilot operated valves shall be used with care in dirty gas service and liquid service.

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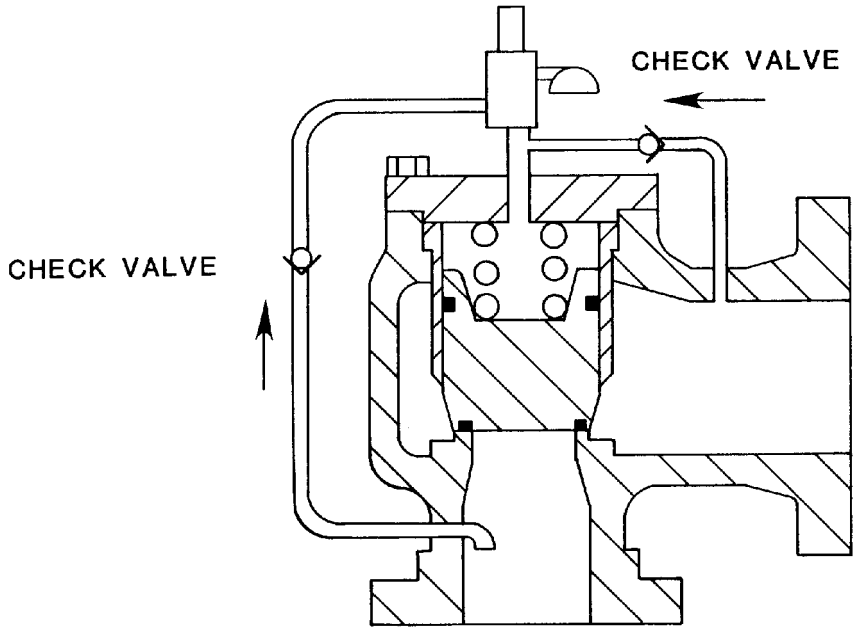
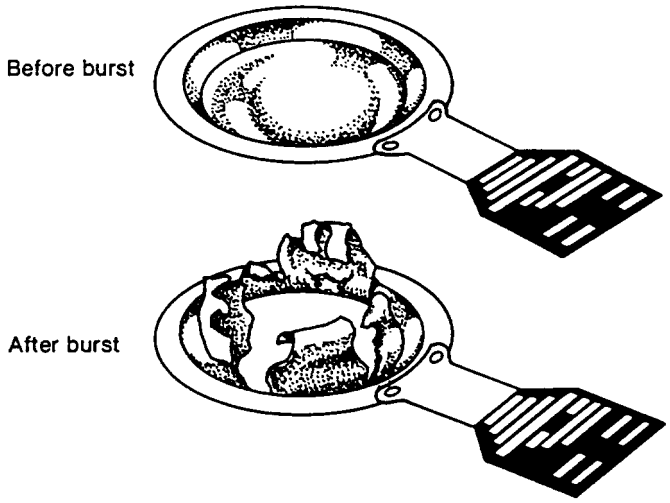


Figure 6: Pilot Operated Valve Backflow Protection by Means of Check Valves

6. Rupture Disks

6.1.

Rupture disks are thin diaphragms held between flanges and designed to burst at a specific static inlet pressure. A conventional rupture disk is shown in Figure 7. These devices cannot reseal when the pressure declines. If the disk ruptures and flow continues into the vessel, the relief system shall be designed for the anticipated flow rate. The disk shall be replaced before the pressure vessel can be placed back in service. Figure 8 shows the relationship between vessel Maximum Allowable Working Pressure (MAWP), and single and multiple rupture disk applications.



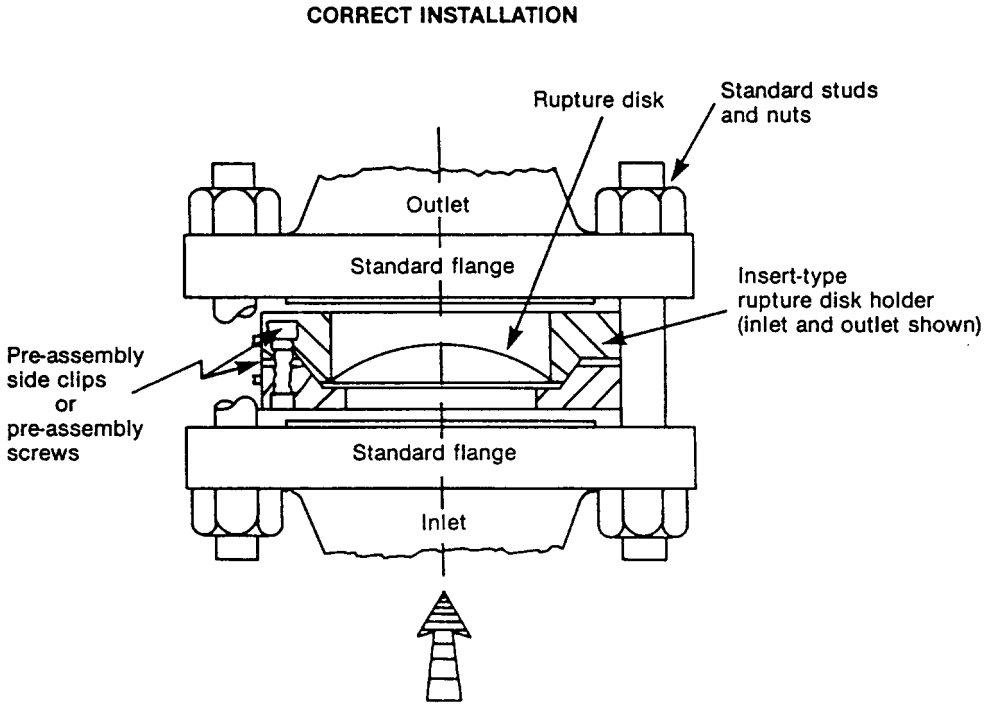
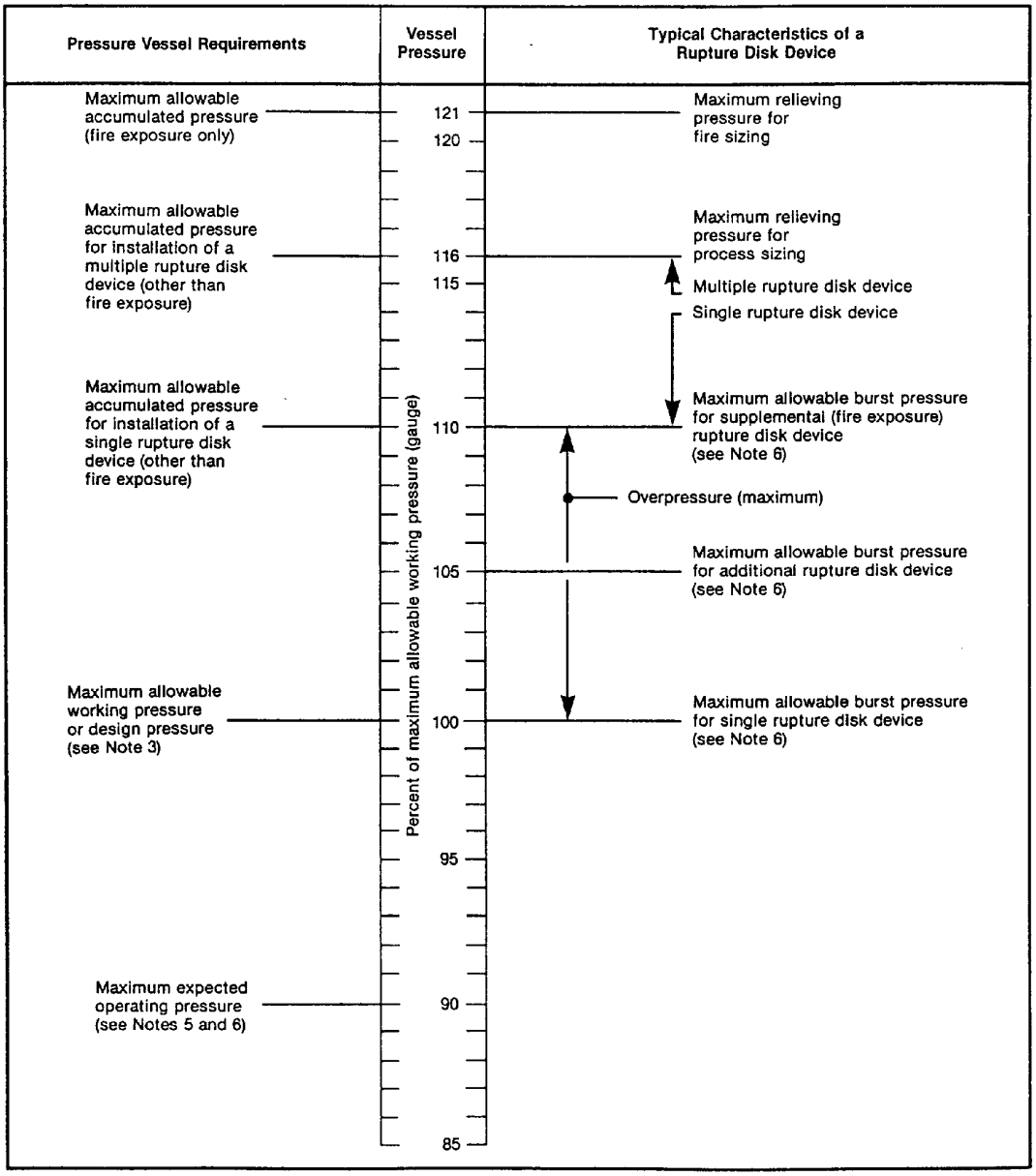


Figure 7: Conventional Rupture Disk (Courtesy of API, from API RP 520 I)


Pressure Vessel Requirements
Vessel Pressure
Typical Characteristics of a Rupture Disk Device
Maximum allowable accumulated pressure (fire exposure only)
Maximum allowable accumulated pressure for installation of a multiple rupture disk device (other than fire exposure)
Maximum allowable accumulated pressure for installation of a single rupture disk device (other than fire exposure)
Maximum allowable working pressure or design pressure (see Note 3)
Maximum expected operating pressure (see Notes 5 and 6)
Percent of maximum allowable working pressure (gauge)
121
120
116
115
110
105
100
95
90
85
Maximum relieving pressure for fire sizing
Maximum relieving pressure for process sizing
Multiple rupture disk device
Single rupture disk device
Maximum allowable burst pressure for supplemental (fire exposure) rupture disk device (see Note 6)
Overpressure (maximum)
Maximum allowable burst pressure for additional rupture disk device (see Note 6)
Maximum allowable burst pressure for single rupture disk device (see Note 6)

Notes:
1. This figure conforms with the requirements of Section VIII of the ASME *Boiler and Pressure Vessel Code*.
2. The pressure conditions shown are for rupture disk devices installed on a pressure vessel.
3. The margin between the maximum allowable working pressure and the operating pressure must be considered in the selection of a rupture disk.
4. The allowable burst-pressure tolerance will be in accordance with the applicable code.
5. The operating pressure may be higher or lower than 90 depending on the rupture disk design.
6. The stamped burst pressure of the rupture disk may be any pressure at or below the maximum allowable burst pressure.

Figure 8: Pressure Level Relationships for Rupture Disk Devices (Courtesy of API, from API RP 520 I)

6.2.

Rupture disks can be manufactured from a variety of materials and with coatings for corrosion resistance. The most common disk materials are aluminum, monel, inconel, stainless steel, and plastic.

6.3.

Rupture disks may be used alone, or as a backup in parallel with a relief valve. If used as a backup, the disk may be set to relieve at approximately 115 percent MAWP (See Figure 7). This ensures that the disk ruptures only if the relief valve fails or is inadequately sized so that when the pressure rises above 110 percent MAWP, the relief valve does not have enough capacity.

6.4.

A rupture disk can also be used in series with a relief valve. Located at the valve inlet to protect the valve from corrosion conditions within the vessel, a rupture disk allows the use of a less expensive valve. Valve internals are protected from the corrosive materials, so specialized metallurgy is not required. Fugitive emissions that pass through pressure relief valves are also eliminated. When properly designed, the rupture disk bursts first, with the relief valve immediately opening. When the pressure declines, the relief valve reseals, limiting additional flow. Additional instrumentation shall be provided so the operator will be advised to replace the ruptured disk. This is also true if the rupture disk develops a small pinhole leak, because the pressure on the back of the disk can build up. Since the rupture disk is designed to fail at a specified differential pressure across the disk, any back-pressure shall cause it to fail at a system pressure higher than the intended relieving pressure. ASME Code requires a free vent, a try-cock, a pressure gauge, or suitable telltale indicator to relieve or sense back-pressure buildup. These shall be monitored so the rupture disk can be replaced if failure occurs.

6.5.

In this application, the relief valve capacity shall be derated by 20 percent unless the manufacturer has established a certified capacity factor for the specific rupture disk/valve combination per ASME SEC VIII D1. The rupture disks shall be non-fragmenting so that pieces of the rupture disk do not block the valve or prevent it from opening. Figure 9 shows a scored, tension-loaded rupture disk, which is normally non-fragmenting.

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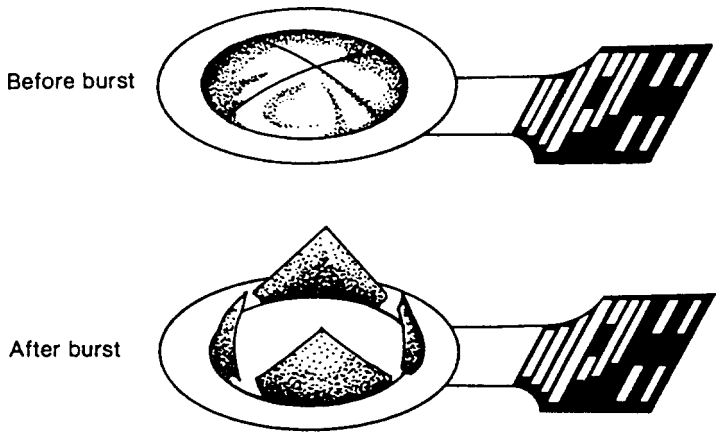


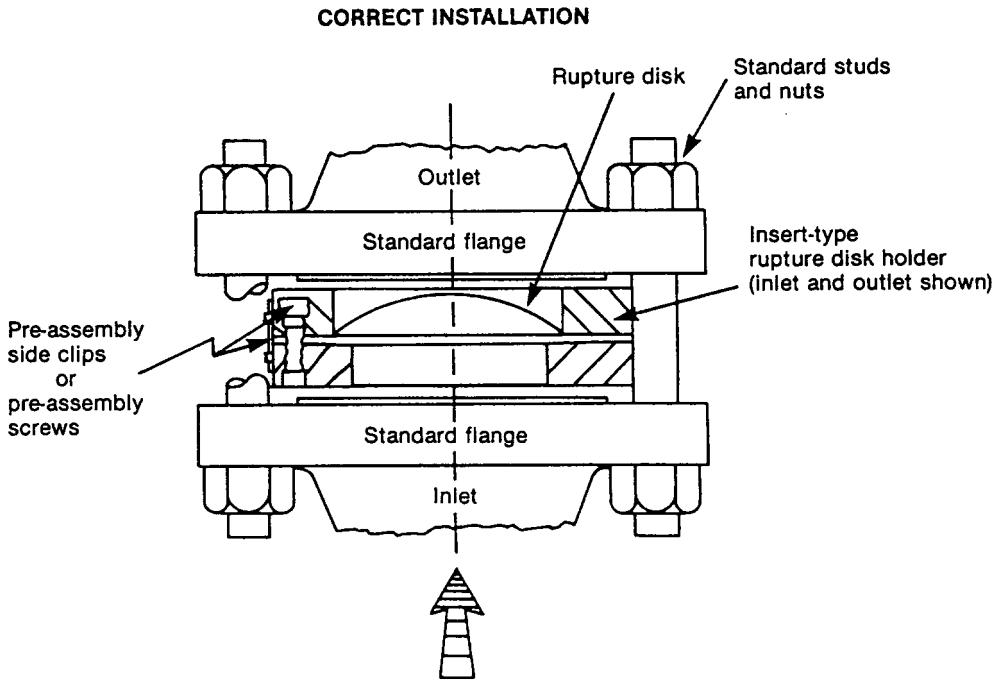


Figure 9: Scored Tension–Loaded Rupture Disk (Courtesy of API, from API RP 520 I)

7. Pressure Relief Valve Sizing

7.1. General

7.1.1.

For safe production facility design, all of the following conditions shall be considered to determine which one governs the size of the relief valve:

1. Blocked discharge. If all outlets from the vessel are assumed to be shut-in, the total design inlet mass flow rate shall be handled by the relief valve. This condition could occur if, after the equipment has been shut-in and isolated, the operator opens the inlet prior to opening the outlet valving.

2. Fire. An external fire can result in vapors evolving from the liquids and in thermal expansion of the gas, which the relief valve shall be able to accommodate. A procedure for calculating this is presented in API RP 520 I. This condition may be critical for large, low-pressure vessels and tanks, but it does not normally govern for most other pressure vessels.

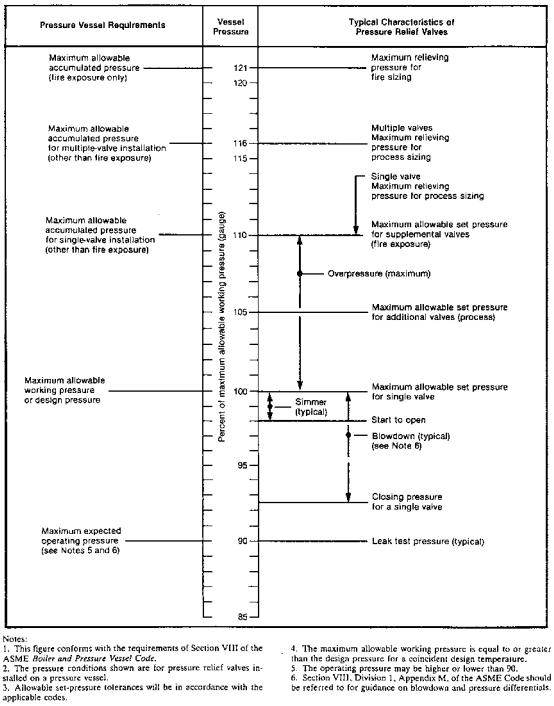
3. Gas blowby. Gas blowby is a critical condition in production facility design. This condition occurs when an upstream liquid control valve fails in the open condition or an upstream manual drain valve is inadvertently left in the open position. The relief valve shall then handle the maximum gas flow rate into the downstream component during this upset condition. For example, if a high-pressure separator were to experience gas blowby, the downstream lower-pressure separator relief valve may have to handle the total design gas flow rate of the high-pressure separator. While this flow may be restricted by an orifice or piping pressure drop, this would not be a conservative assumption. Accidents involving overpressuring of low pressure separators are often a result of relief valves being inadequately sized to handle the gas blowby condition.

4. Thermal Relief. Equipment that is completely full of liquid presents a problem of liquid hydraulic expansion if it is blocked in while heat is added. In many cases, this potential risk can be controlled by design or procedures (see API RP 521). To protect piping or equipment against overpressure resulting from ambient temperature changes, a nominal-size relief device (for example, a 19 by 25 mm, or $^{3}/_{4}$ by 1 in, relief valve) will normally suffice.

7.1.2.

Figure 10 shows the relationships between vessel Maximum Allowable Working Pressure (MAWP) and the safety relief valve set pressure for single

and multiple relief valve installations. For a single relief valve installation, the primary relief valve shall be set to open at no more than 100 percent of the MAWP and sized to relieve the worst case flow rate, either blocked discharge or gas blowby (exclusive of fire), at a pressure of 1.10 MAWP. If two or more relief valves are used to handle the worst case flow rates, the first valve still shall be set no higher than 100 percent MAWP, while the second or last may be set for 1.05 MAWP. Their combined capacity shall relieve the same worst case flow rates at 1.16 MAWP.


Pressure Vessel Requirements
Vessel Pressure
Typical Characteristics of Pressure Relief Valves
Maximum allowable accumulated pressure (fire exposure only)
Maximum allowable accumulated pressure for multiple-valve installation (other than fire exposure)
Maximum allowable accumulated pressure for single-valve installation (other than fire exposure)
Maximum allowable working pressure or design pressure
Maximum expected operating pressure (see Notes 5 and 6)
Percent of maximum allowable working pressure (gauge)
121
120
116
115
110
105
100
95
90
85
Maximum relieving pressure for fire sizing
Multiple valves Maximum relieving pressure for process sizing
Single valve Maximum relieving pressure for process sizing
Maximum allowable set pressure for supplemental valves (fire exposure)
Overpressure (maximum)
Maximum allowable set pressure for additional valves (process)
Maximum allowable set pressure for single valve
Simmer (typical)
Start to open
Blowdown (typical) (see Note 6)
Closing pressure for a single valve
Leak test pressure (typical)

Notes:
1. This figure conforms with the requirements of Section VIII of the ASME *Boiler and Pressure Vessel Code*.
2. The pressure conditions shown are for pressure relief valves installed on a pressure vessel.
3. Allowable set-pressure tolerances will be in accordance with the applicable codes.
4. The maximum allowable working pressure is equal to or greater than the design pressure for a coincident design temperature.
5. The operating pressure may be higher or lower than 90.
6. Section VIII, Division 1, Appendix M, of the ASME Code should be referred to for guidance on blowdown and pressure differentials.

Figure 10: Pressure Level Relationships for Pressure Relief Valve (Courtesy of API, from API RP 520 I)

7.1.3.

The maximum pressure for fire relief rates 1.21 MAWP. Under these relief conditions, the pressure in the vessel shall actually exceed the MAWP. Such occurrences are taken into account by the various safety factors in the ASME Pressure Vessel Code. This situation is one reason the vessel is tested to 1.5 MAWP prior to receiving the code stamp.

7.1.4.

The relief valve shall be installed so that discharged gases and/or liquids are routed to a safe location. In small facilities and remote locations where no liquids are discharged, this may be accomplished with a simple “tail pipe”, which points the discharge vertically upward. A jet in excess of 150 m/sec

(500 ft/sec) dilutes the discharge gases to below the lower flammable limit in approximately 120 pipe diameters.

7.1.5.

Large facilities and offshore platforms where the escaping gases and liquids could present a source of pollution or ignition often route the relief valve discharges into a common header that discharges at a safe location. A vent scrubber is installed in this header to separate the bulk of the liquids and to minimize the possibility of liquid discharges to the surroundings. For relief systems with a common header, the back- pressure developed in the header shall be checked for various relieving scenarios. When reliefs discharge into a common header, the header pressure shall increase. As discussed previously, this back-pressure can adversely affect relief valve performance by causing the valve to open at a higher pressure, or it may restrict the flow capacity. The effect depends on the type of relief valve and the severity of the back-pressure. The design of headers, scrubbers, and vent or flare systems is beyond the scope of this tutorial and is covered in API RP 521. Specific header sizing information is included in the tutorial EPT 04-T-02 on Flare and Vent Systems.

7.2. Gas or Vapor Service

7.2.1. General

1. The maximum flow of a compressible fluid through an orifice occurs at sonic velocity. Sonic velocity is maintained as long as the pressure drop through the orifice is sufficiently high.

2. Critical Pressure Ratio (γ_c) is the largest ratio of downstream pressure to upstream pressure capable of producing sonic velocity. It is dependent on the specific heat ratio of the fluid:

   Equation 1

$$\gamma_c = \frac{P_{cf}}{P_1} = \left[\frac{2}{k+1}\right]^{\frac{k}{k-1}}$$

   where :

   $\gamma_c = critical\ \ pressure\ ratio$

   $k = specific\ heat\ ratio, C_p / C_v$

   $P_{cf} = critical\ \ flow\ outlet\ \ pressure, kPa\ (psia)$

   $P_1 = inlet\ \ pressure, kPa\ (psia)$

3. Values of k and molecular weights for common gases are shown in Table 1. Critical Flow Pressure is slightly greater than half of the inlet pressure for gases with specific heat ratios < 1.5.

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Table 1: Molecular Weights and $k=C_P/C_V$ for Common Gases

Gas	Molecular Weight	Specific Heat Ratio (k = Cp/Cv) at 15.6°C and 100 kPa (60°F and 1 Atmosphere)
Methane	16.04	1.31
Ethane	30.07	1.19
Ethylene	28.03	1.24
Propane	44.09	1.13
Propylene	47.08	1.15
Isobutane	58.12	1.18
n-Butane	58.12	1.19
Isopentane	72.13	1.08
n-Pentane	72.15	1.08
n-Hexane	84.17	1.06
Benzene	78.11	1.12
n-Heptane	100.20	1.05
Toluene	92.13	1.09
n-Octane	114.22	1.05
n-Nonane	128.23	1.04
n-Decane	142.28	1.03
Air	28.96	1.40
Ammonia	17.03	1.30
Carbon dioxide	44.01	1.29
Hydrogen	2.02	1.41
Hydrogen sulfide	34.08	1.32
Sulfur dioxide	64.04	1.27
Steam	18.01	1.33
Source: API 520 (with Isobutane molecular weight corrected)		

4. The rate of gas flow through an orifice or nozzle is a function solely of the inlet pressure when the back-pressure is less than the critical flow pressure (critical flow). When the outlet back-pressure is greater than the critical flow pressure, the gas rate is then also a function of outlet pressure (subcritical flow).

5. The value of k can be accurately calculated as described in the tutorials EPT 07-T-03A and EPT 07-T-03B on Reciprocating Compressors, provided the gas composition is known. When this is not the case, k can be estimated from Figure 11, based on:

Equation 2

$$k = \frac{C_P}{C_V} \sim 1 + \frac{5.1}{29\ SG} = 1 + \frac{5.1}{MW}$$

where :

SG = gas specific gravity relative to air

MW = gas molecular weight

C_P *= specific heat at constant pressure*

C_V *= specific heat at constant volume*

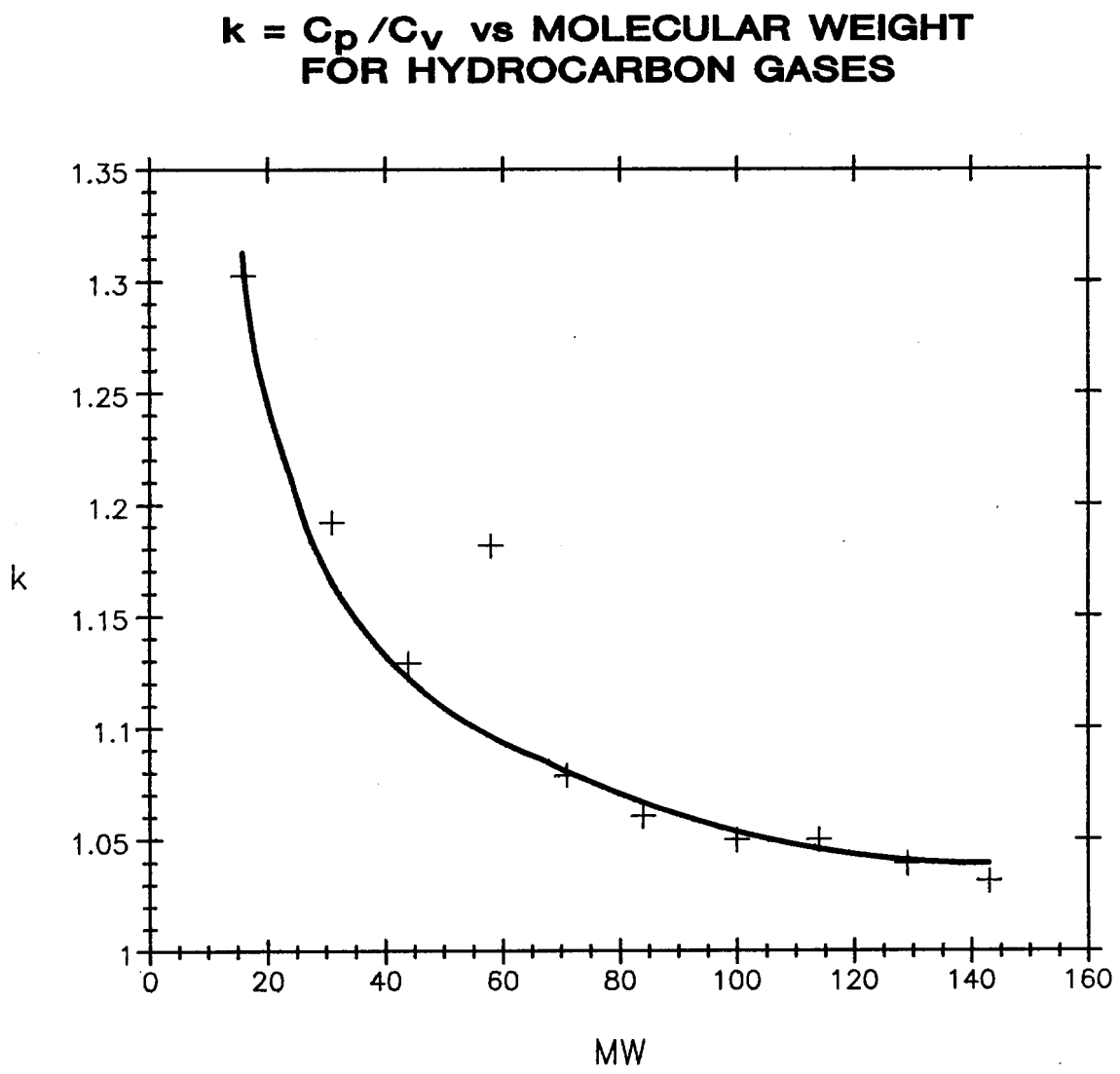

Figure 11: Specific Heats Ratio Versus Molecular Weight for Hydrocarbon Gases (Courtesy of API, from API RP 520 I)

6. The sizing equations for pressure relief valves in vapor service fall into two general categories, critical or subcritical.

7. If the pressure downstream of the throat is less than or equal to the critical flow pressure, P_{cf}, then critical flow shall occur, and the procedures in Section 7.2.2 shall be applied.

8. If the downstream pressure exceeds the critical flow pressure, P_{cf}, then subcritical flow shall occur, and the procedures in Section 7.2.3 shall be applied.

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7.2.2. Sizing for Critical Flow

1. Pressure relief valves in vapor service may be sized using Equations (3) through (5) when governed by critical flow. Each equation may be used to calculate the effective pressure relief valve discharge area, a, required to achieve the design flow rate.

Equation 3

Metric :

$$a = \frac{13{,}157W}{CK_d P_1 K_b}\sqrt{\frac{TZ}{MW}}$$

Customary :

$$a = \frac{W}{C\,K_d\,P_1\,K_b}\sqrt{\frac{TZ}{MW}}$$

Equation 4

Metric :

$$a = \frac{555.79V\sqrt{TZMW}}{CK_d P_1 K_b}$$

Customary :

$$a = \frac{V\sqrt{T\,Z\,MW}}{6.32\,C\,K_d\,P_1\,K_b}$$

Equation 5

Metric :

$$a = \frac{2993V\sqrt{TZSG}}{CK_d P_1 K_b}$$

Customary :

$$a = \frac{V\sqrt{T\,Z\,SG}}{1.175\,C\,K_d\,P_1\,K_b}$$

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where :

a = *required effective discharge area of valve,* $mm^2\ (in^2)$

W = *required flow through the valve,* $kg/hr\ (lb/hr)$

C = *coefficient determined from the ratio of the specific heats of the gas or vapor at standard conditions. This can be obtained from Figure 12 or Table 2.*

K_d = *valve coefficient of discharge (from valve manufacturer). For Farris and Consolidated spring operated,* $K_d = 0.975$. *For AGCO type 23 and 33 pilot operated,* $K_d = 0.92$.

P_1 = *upstream relieving pressure,* $kPa\ (psia)$. *This is the set pressure plus the allowable overpressure plus atmosperic pressure.*

$= P_{set} + P_{ov} + 100\ kPa\ (= P_{set} + P_{av} + 14.7\ psi)$

P_{set} = *set pressure,* $kPa\ (psig)$

P_{ov} = *overpressure,* $kPa\ (psig)$

$$= P_{set} \times \left[\frac{\text{percent overpressure}}{100} \right]$$

Percent overpressure = 10 *for operational relief condition*

= 20 *fire relief condition*

MW = *molecular weight of gas*

Z = *compressibility factor*

T = *flowing temperature,* $K\ (^oR)$

K_b = *back - pressure correction factor. Obtain this correction factor from valve manufacturer when available, or use Figure 13 for balanced bellows safety relief valves.*

V = *required flow through the valve, std* m^3/hr *at 100 kPa and* $15.56^oC\ (SCFM$ *at 14.7 psia and* $60^oF)$

SG = *specific gravity of gas relative to air*

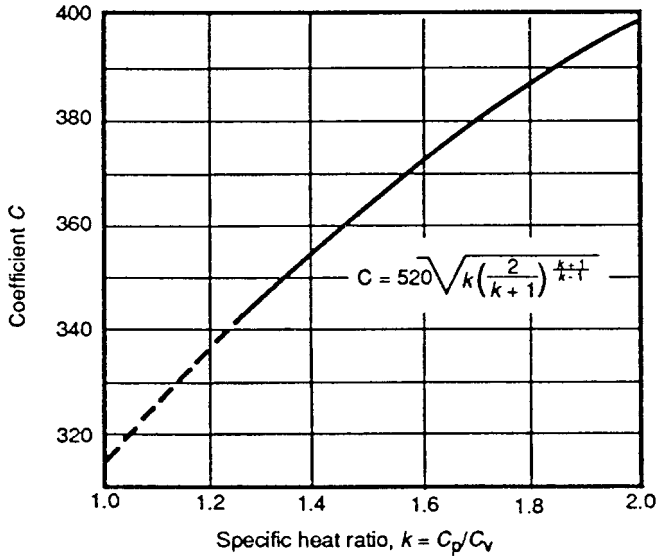
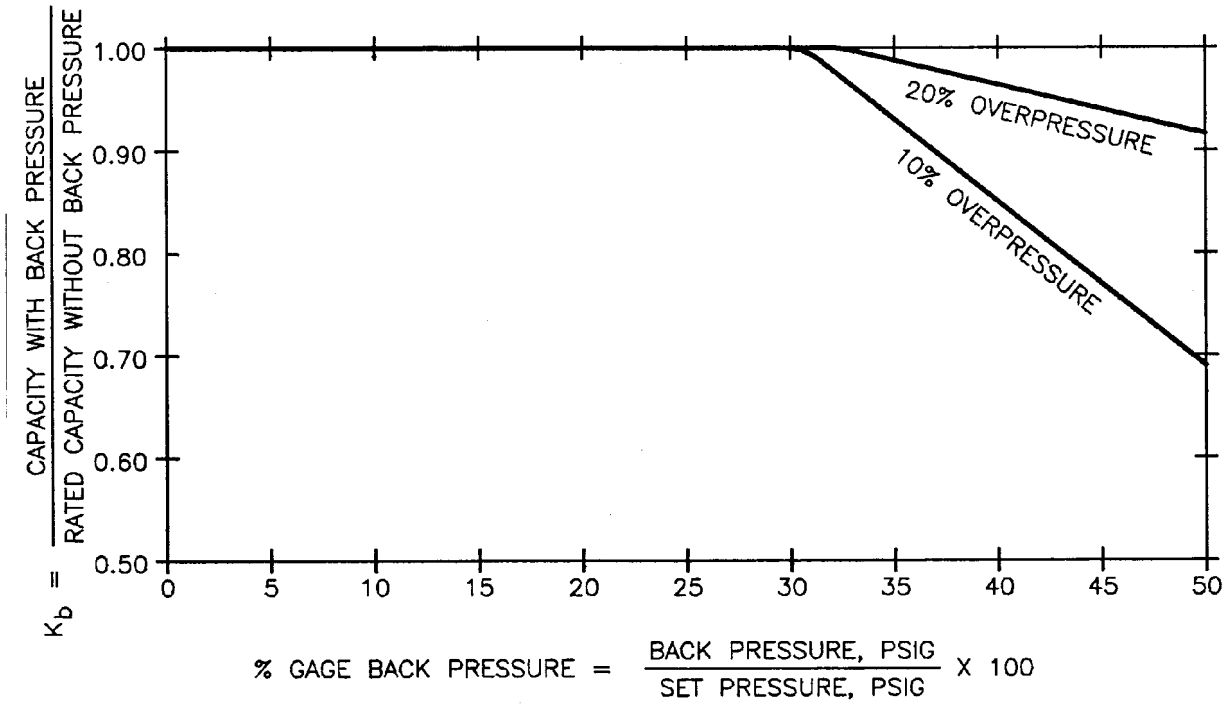


Figure 12: Coefficient C Versus Specific Heats Ratio (Courtesy of API, from API RP 520 I)

Table 2: Value of Coefficient C

k	C	k	C	k	C
1.01	316.56	1.31	347.91	1.61	373.32
1.02	317.74	1.32	348.84	1.62	374.09
1.03	318.90	1.33	349.77	1.63	374.85
1.04	320.05	1.34	350.68	1.64	375.61
1.05	321.19	1.35	351.60	1.65	376.37
1.06	322.32	1.36	352.50	1.66	377.12
1.07	323.44	1.37	353.40	1.67	377.86
1.08	324.55	1.38	354.29	1.68	378.61
1.09	325.65	1.39	355.18	1.69	379.34
1.10	326.75	1.40	356.06	1.70	380.08
1.11	327.83	1.41	356.94	1.71	380.80
1.12	328.91	1.42	357.81	1.72	381.53
1.13	329.98	1.43	358.67	1.73	382.25
1.14	331.04	1.44	359.53	1.74	382.97
1.15	332.09	1.45	360.38	1.75	383.68
1.16	333.14	1.46	361.23	1.76	384.39
1.17	334.17	1.47	362.07	1.77	385.09
1.18	335.20	1.48	362.91	1.78	385.79
1.19	336.22	1.49	363.74	1.79	386.49
1.20	337.24	1.50	364.56	1.80	387.18
1.21	338.24	1.51	385.39	1.81	387.87
1.22	339.24	1.52	366.20	1.82	388.56
1.23	340.23	1.53	367.01	1.83	389.24
1.24	341.22	1.54	367.82	1.84	389.92
1.25	342.19	1.55	368.82	1.85	390.59
1.26	343.16	1.56	369.41	1.86	391.25
1.27	344.13	1.57	370.21	1.87	391.93
1.28	345.08	1.58	370.99	1.88	392.59
1.29	346.03	1.59	371.77	1.89	393.25
1.30	346.98	1.60	372.55	1.90	393.91
Source: API 520					



NOTE: THE ABOVE CURVES REPRESENT A COMPROMISE OF THE VALUES RECOMMENDED BY A NUMBER OF RELIEF VALVE MANUFACTURERS AND MAY BE USED WHEN THE MAKE OF VALVE OR THE CRITICAL FLOW PRESSURE POINT FOR THE VAPOR OR GAS IS UNKNOWN. WHEN THE MAKE IS KNOWN, THE MANUFACTURER SHOULD BE CONSULTED FOR THE CORRECTION FACTOR.
THESE CURVES ARE FOR SET PRESSURES OF 50 PSIG AND ABOVE; FOR SET PRESSURES LOWER THAN 50 PSIG, THE MANUFACTURER SHOULD BE CONSULTED FOR THE VALUES OF K.

Figure 13: Variable or Constant Back-Pressure Sizing Factor, K_b, for Balanced Bellows Safety Relief Valves (Vapors and Gases) (Courtesy of API, from API RP 520 I**)**

2. A standard orifice size may be selected from Table 3.

Table 3: Standard Orifice Areas and Designations (From API Standard 526)

Orifice	Area (Square in)
D	0.110
E	0.196

F	0.307
G	0.503
H	0.785
J	1.287
K	1.838
L	2.853
M	3.60
N	4.43
P	6.38
Q	11.05
R	16.0
T	26.0

3. Alternately, Equations (3), (4), and (5) may be rearranged to solve for flow rates for a given area:

Equation 6

Metric :

$$W = \frac{aCK_d P_1 K_b}{13{,}157}\sqrt{\frac{MW}{TZ}}$$

Customary :

$$W = a\,C\,K_d\,P_1\,K_b\sqrt{\frac{MW}{TZ}}$$

Equation 7

Metric :

$$V = \frac{aCK_d P_1 K_b}{555.79\sqrt{TZMW}}$$

Customary :

$$V = \frac{6.32\,a\,C\,K_d\,P_1\,K_b}{\sqrt{T\,Z\,MW}}$$

Equation 8

Metric :

$$V = \frac{aCK_d P_1 K_b}{2993\sqrt{TZSG}}$$

Customary :

$$V = \frac{1.175\, a\, C\, K_d\, P_1\, K_b}{\sqrt{T\, Z\, SG}}$$

7.2.3. Sizing for Subcritical Flow

1. If the ratio of back-pressure to inlet pressure exceeds the critical pressure ratio P_{cf}/P_1, the flow through the pressure relief valve is then subcritical. Equations (9) through (11) are used to calculate the required effective discharge area for conventional relief valves that have springs adjusted to compensate for superimposed back-pressure or to calculate the required effective discharge area for a pilot-operated relief valve. Sizing of balanced-bellows relief valves under conditions of subcritical flow shall be done using Equations (3) through (5). For these valves, the back-pressure correction factor shall be obtained from the manufacturer.

   Equation 9

   Metric :

$$a = \frac{17.90W}{F_2 K_d}\sqrt{\frac{ZT}{MWP_1\left(P_1 - P_2\right)}}$$

   Customary :

$$a = \frac{W}{735\, F_2\, K_d}\sqrt{\frac{ZT}{MW\; P_1\left(P_1 - P_2\right)}}$$

Equation 10

Metric :

$$a = \frac{0.756V}{F_2 K_d}\sqrt{\frac{ZTMW}{P_1(P_1 - P_2)}}$$

Customary :

$$a = \frac{V}{4645.2\ F_2\ K_d}\sqrt{\frac{ZT\ MW}{P_1\ (P_1 - P_2)}}$$

Equation 11

Metric :

$$a = \frac{4.07V}{F_2 K_d}\sqrt{\frac{ZT\ SG}{P_1(P_1 - P_2)}}$$

Customary :

$$a = \frac{V}{863.63\ F_2\ K_d}\sqrt{\frac{ZT\ SG}{P_1\ (P_1 - P_2)}}$$

where :

$F_2 = coefficient\ of\ subcritical\ flow\ (see\ Figure\ 14\ for\ values)$

$$= \sqrt{\left(\frac{k}{k-1}\right) r^{\frac{2}{k}} \left[\frac{1 - r^{\frac{(k-1)}{k}}}{1 - r}\right]}$$

$r = ratio\ of\ back\text{-}pressure\ to\ upstream\ relieving\ pressure, P_2 / P_1$

$P_2 = back\text{-}pressure, kPa\ (psia)$

$= P_b + 100\ kPa\ (= P_b + 14.7\ psia)$

$P_b = back\text{-}pressure, kPa\ (psig)$

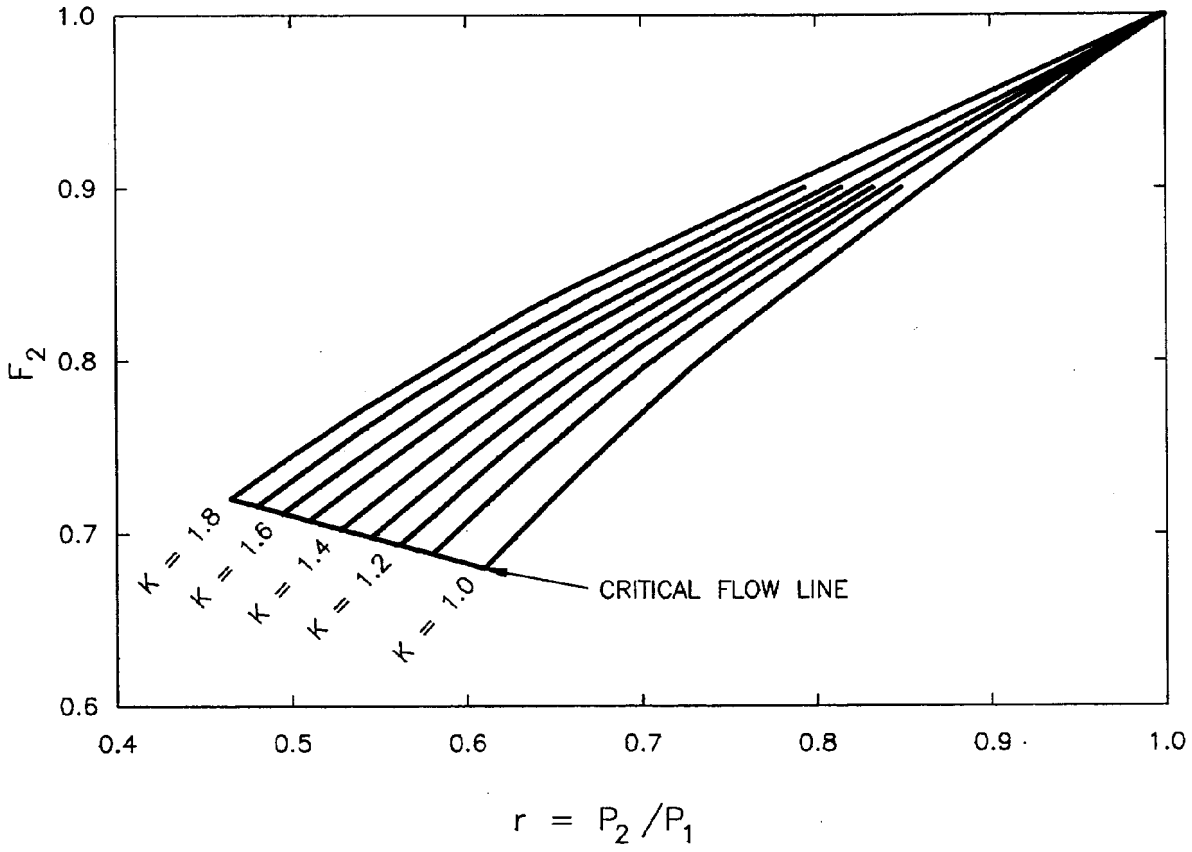


Figure 14: Values of Subcritical Flow Coefficient F_2 (Courtesy of API, from API RP 520 I)

1. Equations (9), (10), and (11) may be solved for flow rates for a given area:

   Equation 12

   Metric :

   $$W = \frac{aF_2K_d}{17.90}\sqrt{\frac{MWP_1(P_1 - P_2)}{ZT}}$$

   Customary :

   $$W = 735\, a\, F_2\, K_d \sqrt{\frac{MW\, P_1\,(P_1 - P_2)}{Z\, T}}$$

Equation 13

Metric :

$$V = \frac{aF_2K_d}{0.756}\sqrt{\frac{P_1(P_1 - P_2)}{ZT\,MW}}$$

Customary :

$$V = 4645.2\,a\,F_2\,K_d\sqrt{\frac{P_1\,(P_1 - P_2)}{Z\,T\,MW}}$$

Equation 14

Metric :

$$V = \frac{aF_2K_d}{4.07}\sqrt{\frac{P_1(P_1 - P_2)}{ZT\,SG}}$$

Customary :

$$V = 863.63\,a\,F_2\,K_d\sqrt{\frac{P_1\,(P_1 - P_2)}{Z\,T\,SG}}$$

7.3. Steam Service

7.3.1.

Pressure relief valves in steam service are sized as follows:

Equation 15

Metric :

$$a = \frac{190.42W}{P_1K_dK_NK_{SH}}$$

Customary :

$$a = \frac{W}{51.5\,P_1\,K_d\,K_N\,K_{SH}}$$

where :

K_d = *valve coefficient of discharge (from valve manufacturer). For Farris and Consolidated spring operated,* $K_d = 0.975$. *For AGCO type 23 and 33 pilot operated,* $K_d = 0.92$.

K_N = *correction factor for Napier equation*

$= 1$ *where* $P_1 \le 10{,}446$ *kPa* $(1515$ *psia)*

$$= \frac{0.0280\,P_1 - 1000}{0.0337\,P_1 - 1061} \quad \text{where } 10{,}446 \text{ kPa} \le P_1 \le 22{,}167 \text{ kPa}$$

$$= \frac{0.1906\,P_1 - 1000}{0.2292\,P_1 - 1061} \quad \text{where } 1515 \text{ psia} < P_1 \le 3215 \text{ psia}$$

K_{SH} = *superheat steam correction factor. This can be obtained from API RP 520, Table 10, Superheat Correction Factors,* K_{SH}. *For saturated steam at any pressure,* $K_{SH} = 1.0$.

7.3.2.

Alternately, the mass flow rate may be calculated from the valve discharge area:

Equation 16

Metric :

$$W = \frac{aP_1K_dK_NK_{SH}}{190.42}$$

Customary :

$$W = 51.5\,a\,P_1\,K_d\,K_N\,K_{SH}$$

7.4. Liquid Service

7.4.1.

The procedure for obtaining capacity certification per ASME SEC VIII D1 includes determination of the coefficient of discharge for the design of liquid relief valves at 10 percent overpressure. Valves that require a capacity in accordance with the ASME Code are sized using:

Equation 17

Metric :

$$a = \frac{196.3Q}{K_d K_W K_V} \sqrt{\frac{SG_L}{P_1 - P_2}}$$

Customary :

$$a = \frac{Q}{38\, K_d\, K_W\, K_V} \sqrt{\frac{SG_L}{P_1 - P_2}}$$

where :

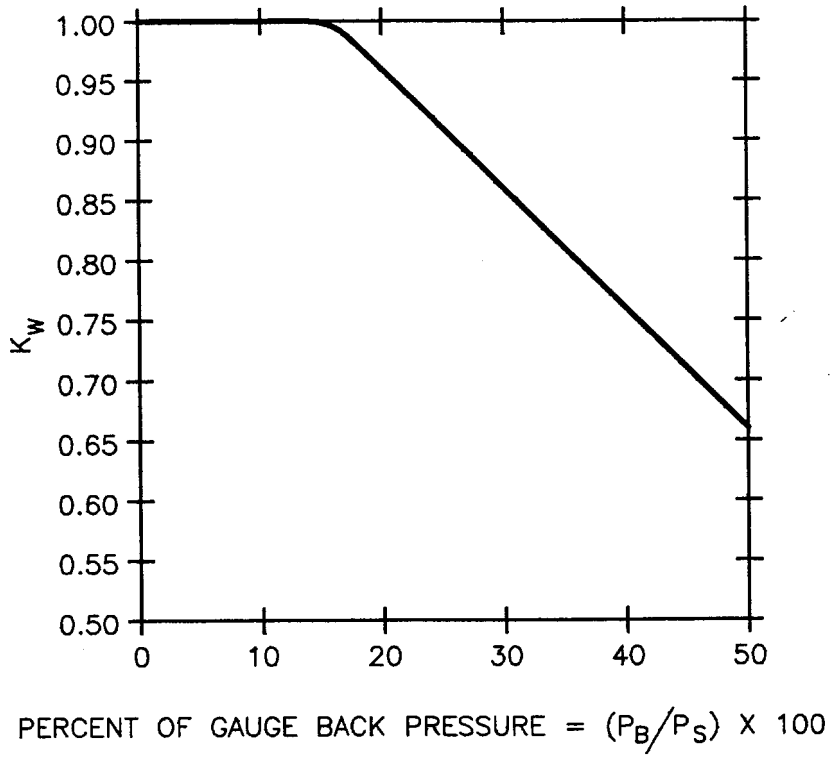
$Q =$ *flow rate at flowing temperature,* $m^3 / hr\ (gpm)$

$K_d =$ *effective coefficient of discharge that should be obtained from the valve manufacturer. For a preliminary sizing estimation a discharge coefficient of 0.65 can be used.*

$K_W =$ *correction factor due to back - pressure. If the back - pressure is atmospheric,* $K_W = 1$*. Balanced - bellows valves in back - pressure service will require the correction factor determined from Figure 15. Conventional valves require no special correction.*

$K_V =$ *correction factor due to vicosity as determined from Figure 16.*

$SG_L =$ *specific gravity of liquid at flowing temperature, relative to water*



K_W = CORRECTION FACTOR DUE TO BACK PRESSURE.
P_B = BACK PRESSURE, IN POUND PER POUNDS PER SQUARE INCH GAUGE.
P_S = SET PRESSURE, IN POUNDS PER SQUARE INCH GAUGE.

NOTE: THE CURVE ABOVE REPRESENTS VALUES RECOMMENDED BY VARIOUS MANUFACTURES. THIS CURVE MAYBE USED WHEN THE MANUFACTURER IS NOT KNOWN. OTHERWISE, THE MANUFACTURER SHOULD BE CONSULTED FOR THE APPLICABLE CORRECTION FACTOR.

Figure 15: Correction Factor Due to Back-Pressure on Balanced Bellows Pressure Relief Valves in Liquid Service (Courtesy of API, from API RP 520 I)

7.4.2.

For viscous liquid service, a relief valve shall first be sized as if it were for nonviscous service to obtain a preliminary required discharge area, a. The next larger standard orifice size shall then be used in determining the Reynolds number, R, from either of the following relationships:

Equation 18

Metric :

$$R = \frac{313.13QSG_L}{\mu\sqrt{a}}$$

Customary :

$$R = \frac{Q\left(2800\ SG_L\right)}{\mu\sqrt{a}}$$

Equation 19

Metric :

$$R = \frac{1{,}420{,}000Q}{U\sqrt{a}}$$

Customary :

$$R = \frac{12700\ Q}{U\sqrt{a}}\ \ for\ U > 100\ SUS$$

where :

$R = Reynolds\ number$

$\mu = absolute\ viscosity\ at\ theflowing\ temperature, Pa\ s\ (cp)$

$a = effective\ discharge\ area, mm^2\ (in^2)\left(\begin{array}{c} from\ manufacturer's \\ standard\ orifice\ areas \end{array}\right)$

$U = viscosity\ at\ the\ \ flowing\ temperature, mm^2/s\left(\begin{array}{c} Saybolt \\ Universal\ sec \end{array}\right)$

7.4.3.

After the value of R is determined, the factor K_v is obtained from Figure 16. K_v is used to find the required discharge area. If the corrected area exceeds the chosen standard orifice area, the calculation shall be repeated using the next larger standard orifice size.

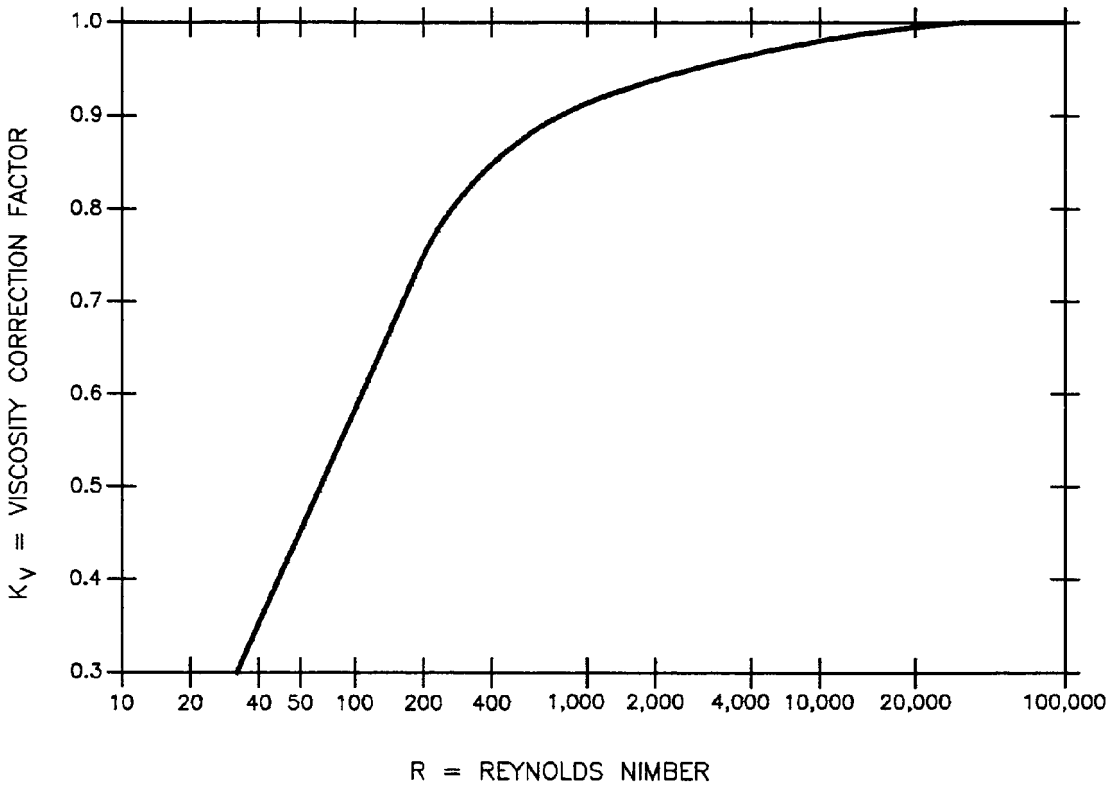


Figure 16: Capacity Correction Factor Due to Viscosity (Courtesy of API, from API RP 520 I)

7.5. Two-Phase Flow

7.5.1.

In production operations many relief valves shall be sized for handling fluids containing both liquid and gas. In addition, most liquid reliefs will produce flashing and vapor generation as the fluid moves through the valve. The vapor generation shall be considered since it may reduce the effective mass flow capacity of the valve.

7.5.2.

There are presently no precise formulas for calculating orifice area for two-phase flow. The common convention is to calculate the area required for the gas and liquid flows separately as single phase flows. The two areas are then added to approximate the area required for two-phase flow.

7.5.3.

When liquids that are at their vapor pressure are to be relieved, the designer shall calculate the backpressure downstream of the relief valve due to two-phase flow in the relief header. The flow rate of vapor generated due to pressure drop through the relief valve can then be determined and the relief valve sized for two phase flow. This is an iterative solution, as the amount of vapors generated by pressure drop through the relief valve depends upon the backpressure, which is a function of two-phase pressure drop in the header.

7.5.4.

The designer shall also consider the effect of any auto refrigeration that may be caused by the flashing of liquid. Materials of construction shall be adequate for the outlet temperatures involved. In addition, the possibility of flow blockage occurring from hydrates or other blockages shall be considered in the installation design when auto refrigeration conditions exist.

7.6. Effects of Back-pressure on Capacity

7.6.1.

Reduced relief valve capacity occurs when back-pressure exceeds the following approximate percentage of set pressure plus allowable overpressure:

1. Spring loaded 60 percent
2. Balanced bellows 35 percent
3. Pilot operated 60 percent

7.6.2.

In relief valves other than balanced bellows relief valves, liquid flow capacity is proportional to pressure drop across the valve. Bellows valves have a further reduction in capacity with back-pressure. Where high back-pressure exist, therefore, this type of relief valve has a potential disadvantage when compared to the other two types.

7.7. Installation

7.7.1.

Relief valve inlet piping shall be as short as practical, and each relief valve shall be equipped with inlet piping no smaller than the valve inlet flange size. The inlet piping pressure drop from the source to the relief valve inlet flange shall not exceed 3 percent of the valve set pressure.

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7.7.2.

Where relief valves are vented to the atmosphere, they shall have “tail pipes” equal to or larger in diameter than the relief valve outlet. These pipes shall extend vertically a minimum of 0.3 m (1 ft) above building eaves or, in operating areas with adjacent platforms, 2.4 m (8 ft) above the platform level. The tail pipe shall be provided with a small drain hole to keep rainwater or condensed liquids from accumulating in the tailpipe. The drain hole shall be located such that the exhaust through the drain hole does not impinge on vessels, piping, other equipment, or personnel.

7.7.3.

Piping shall be installed in such a manner that liquid in the relief valve piping shall drain into the relief header. This liquid is removed in the vent scrubber (see tutorial the EPT 04-T-02 on Flare and Vent Systems for information on header design.) Unavoidable low spots in the piping shall be equipped with drain valves piped to a safe location.

7.7.4.

Relief valves shall be tested on a periodic basis even if testing is not required by regulations. Pilot operated valves can be tested by sending a test signal to the pilot through a test connection in the pilot sensing line. Spring loaded relief valves shall either: (1) be removed from service; (2) be tested by subjecting the equipment being protected to set pressure; or (3) have an upstream block valve provided, which can isolate the relief valve from the equipment being protected, and a test connection between the block and relief valves installed. There is no industry consensus on which of these three test methods provides the highest level of safety. Therefore, some relief valves are installed with upstream block valves and some without.

7.7.5.

If relief valves discharge to a common header, it is sometimes convenient to install downstream block valves so that the relief valve can be removed for repairs without shutdown of all equipment tied into the common header. The increase in operating flexibility may not be worth the decrease in safety if the downstream block valve is inadvertently left closed.

7.7.6.

Where either upstream or downstream block valves are used they shall be full open gate or ball valves with a device that enables them to be locked open and sealed. These are referred to as “car-seal-open” valves.

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7.7.7.

Various arrangements employing three-way valves and multiple relief valves are sometimes used to provide the benefits of being able to isolate the relief valve for testing and maintenance without the disadvantage of decreasing safety through inadvertent closing of a block valve. Three-way valve arrangements are much more costly than ordinary block valves. Table 1 in MP 70-P-06 provides guidance for Mobil installations.

7.7.8.

As much as possible, relief valves shall be accessible from platforms. Where relief valves must be removed for testing, those with 100 mm (4 in) and larger inlet sizes often have davits or other lift equipment nearby for lowering them to the ground. Relief valve connections to equipment and all relief piping shall be designed to withstand the high impact forces that occur when the valve opens. Discharge piping supports shall be arranged to minimize moments at the connection to the equipment being protected.

7.8. Rupture Disk Sizing

7.8.1. Rupture Disk Devices Used Independently

1. Rupture disk devices may be used alone or in combination with a pressure relief valve in vapor service or in liquid service. For all fluids an effective coefficient of discharge $K_d = 0.62$ shall be used in the equation for relief valves when sizing a rupture disk for stand-alone service.

2. The required discharge area, a, is calculated using the appropriate equation for the flowing medium (see Equations [3] through [14] for vapor and Equation [17] for liquid). The rupture disk shall be selected so that the area is equal to or greater than the required discharge area calculated by the appropriate equation.

3. For rupture disk devices that have a structural member (for example, a knife blade or vacuum support) that reduces the effective discharge area after bursting, the projected area of the structural member shall be deducted from the flow area of the pipe. This gives a net discharge area for the rupture disk to be used in the calculations.

4. Users shall be aware that, when using $K_d = 0.62$ to determine the capacity of a given size of rupture disk or, conversely, the required area for a given flow quantity:

    a) The rupture disk device shall be selected in a size and pressure range that the manufacturer has determined will give a satisfactory opening for the style of rupture disk in the particular fluid service.

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b) The rupture disk device shall be installed in a piping system short enough that it does not add significantly to the flow resistance of the burst rupture disk device.

5. If a rupture disk device discharges into a vent system or a closed relief system, it will usually not contribute significantly to the pressure drop in the piping system. Sizing of the disk becomes a line sizing problem that uses the relieving rate and the maximum allowable inlet pressure defined by the code. In general, the rupture disk can be considered to have an equivalent length of 75 pipe diameters. The manufacturer shall be consulted if more accurate values are required.

7.8.2. Rupture Disks Used with Relief Valves

1. One important application of a rupture disk device is at the inlet of a pressure relief valve. The sizing of the pressure relief valve/rupture disk device combination requires that the pressure relief valve first be sized to meet the required relieving capacity. The certified and published capacity of the pressure relief valve used alone is then multiplied by the combination capacity factor, K_c, to determine the capacity of that combination. $K_c = 0.80$ unless the manufacturer has established another certified value in accordance with ASME SEC VIII.

2. The nominal size of the rupture disk device installed at the inlet of the pressure relief valve shall be equal to or greater than the nominal size of the inlet connection of the valve to permit sufficient flow capacity and valve performance.

3. The design of the piping from the protected vessel to the inlet of the pressure relief valve is crucial to the proper functioning of the valve. The frictional pressure loss from the vessel to the relief valve inlet, including the loss through the rupture disk, shall be less than 3 percent of the relief valve set pressure. An inlet pipe and rupture disk sized larger than would be necessary if the pressure relief valve alone were used for relief are often necessary.

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Appendix A–Nomenclature

Operating Pressure	The operating pressure is that pressure normally exerted on the component or system. Because fluctuations in process pressure can occur as the control system reacts to changes in flow rate, temperature, etc., the design pressure shall always be higher than the operating pressure.
Huddling Chamber	The huddling chamber results from the shape of the seat disk and the outlet of the relief valve inlet nozzle. Because the disk is larger than the nozzle outlet with sides that come down around the nozzle throat, an annular area is created, forming the huddling chamber. When the seat lifts, higher pressure from the nozzle escapes into the huddling chamber. Although the nozzle area pressure may be somewhat reduced, the seat is forced open because higher pressure is applied to the additional area of the disk in the huddling chamber. This action increases the reliability of the relief valve opening.
Gag	When the relief valve body is pressure tested, it is necessary to prevent the seat disk from lifting off the seat. This is accomplished by use of a threaded rod or "gag" which is inserted into the top of the bonnet and depresses the seat disk so that the valve remains closed against the test pressure.
Flutter	The condition when the set pressure/relieving characteristics of a relief valve cause the seat disk to reciprocate rapidly without contacting the valve seat is called flutter.
Chatter	The condition when the set pressure/relieving characteristics of a relief valve cause the seat disk to repeatedly lift and reseat, thereby damaging the seat and associated piping, is called chatter.

a = effective discharge area of valve, mm^2, in^2

C = coefficient determined from the ratio of specific heats

C_P = specific heat at constant pressure

C_V = specific heat at constant volume

F_2 = coefficient of subcritical flow

k = specific heat ratio, C_p/C_v

K_b = back-pressure correction factor

K_d = valve coefficient of discharge

K_N = correction factor for Napier equation

K_p = correction factor for overpressure

K_{SH} = superheat steam correction factor

K_v = correction factor due to viscosity

K_W = correction factor for liquid due to back-pressure

MW = gas molecular weight

P_o = upstream vessel maximum pressure, kPa (A), psia

P_1 = inlet pressure, kPa (A), psia

P_2 = (absolute) back-pressure = P_b + 101.3 kPa (A), = P_b + 14.7 psia

P_b = back-pressure, kPa (g), psig

P_{cf} = critical flow outlet pressure, kPa (A), psia

P_{OV} = overpressure, kPa (g), psig

P_{set} = set pressure, kPa (g), psig

Q = liquid flow rate, m^3/h, (gpm)

R = Reynolds number

r = ratio of absolute back-pressure to upstream relieving pressure, P_2/P_1

SG = gas specific gravity relative to air

SG_L = specific gravity of liquid relative to water

T = flowing temperature, K, °R

U = viscosity, mm^2/sec, Saybolt Universal seconds

V = flow through valve, standard m^3/hr, SCFM

W = flow through valve, kg/hr, lb/hr

Z = gas compressibility

γ_c = critical pressure ratio

μ = absolute viscosity, Pa-sec, cp

Appendix B–Example Problems - Metric Units

1. Two-Phase Flow

Given:

V	=	Maximum gas flow rate	=	52,000 std m^3/hr
MW	=	Molecular weight of gas	=	23.2
Z	=	Compressibility factor	=	0.75
k	=	Ratio of specific heats	=	1.245
T	=	Flowing temperature	=	38°C
P_{set}	=	Set pressure	=	8270 kPa
P_b	=	Back-pressure	=	3450 kPa
Q	=	Liquid Rate	=	2.38 m^3/hr
SG_L	=	Specific gravity of liquid (Water = 1)	=	0.63
K_d	=	Valve coefficient of discharge for conventional and bellows	=	0.975
K_d	=	Valve coefficient for pilot	=	0.92
K_d	=	Valve coefficient for liquid service	=	0.65
K_v	=	Viscosity correction factor	=	0.95

Determine whether gas flow is critical or subcritical

Calculate orifice size for:

1. Conventional safety relief valve (bonnet vented to atmosphere)
2. Balanced bellows safety relief valve
3. Pilot operated valve

2. Two-Phase Flow

Determine whether gas flow is critical or subcritical

$$\gamma_c = \frac{P_{cf}}{P_1} = \left[\frac{2}{k+1}\right]^{\frac{k}{k-1}}$$

$$P_{cf} = (8270 + 827 + 101.3)\left[\frac{2}{1.245+1}\right]^{\frac{1.245}{(1.245-1)}}$$

$$= 5113\ kPa$$

P_{cf} is greater than the back-pressure of 3450 kPa, so flow through relief valve is critical.

3. Conventional Safety Relief Valve (Vented Bonnet)

4. Calculate Orifice Size for Gas

$$a = \frac{555.79\, V\sqrt{T\ Z\ MW}}{C\ K_d\ P_1\ K_b}$$

where :

$K_b = Back\text{-}pressure\ correction\ factor$

$= 1$

$P_1 = (8270 + 827 + 101.3) = 9198.3\ kPa$

$C = Gas\ constant\ based\ on\ ratio\ of\ specific\ heats\ C_p / C_V$

$= \frac{341.22 + 342.19}{2} = 341.71,\ from\ Table\ 2$

$$a = \frac{555.79\,(52{,}000)\sqrt{(273+38)(0.75)(23.2)}}{(341.71)(0.975)(9198.3)(1)}$$

$$a = 693.7\ mm^3\ \left(1.075\ in^2\right)$$

5. Calculate Orifice Size for Liquid

$$a = \frac{196.3\ Q}{K_d\ K_W\ K_V}\sqrt{\frac{SG_L}{P_1 - P_2}}$$

where :

$P_1 - P_2 = 8270 + 827 - 3450 = 5647\ kPa$

$$a = \frac{196.3\ (2.38)}{(0.65)(1)(0.95)}\sqrt{\frac{0.63}{5647}}$$

$$= 8.0\ mm^2\ (0.012\ in^2)$$

6. Calculate Total Orifice Size

$$a_{TOTAL} = a_L + a_G$$
$$= 693.7 + 8.0$$
$$= 701.7 mm^2 (1.088 in^2) : Use\ valve\ size\ 'J'$$

7. Balanced Bellows Safety Relief Valve

8. Calculate Orifice Size for Gas

$$a = \frac{555.79\,V\sqrt{T\;Z\;MW}}{C\;K_d\;P_1\;K_b}$$

Determine K_b

$$Percent\ Gauge\ Back\text{-}Pressure = \frac{Back\text{-}Pressure, kPa\,(G)}{Set\ Pressure, kPa(G)} \times 100$$

$$= \frac{3450\,(100)}{8270} = 41.7\ percent$$

$$K_b = 0.85\ \ from\ Figure\ 13\ with\ 10\ \ percent\ overpressure$$

$$a = \frac{555.79\,(52{,}000)\sqrt{(273+38)(0.75)(23.2)}}{(341.71)(0.975)(9198.3)(0.85)}$$

$$= 816.2\ \ mm^3\ \left(1.265\ in^2\right)$$

9. Calculate Orifice Size for Liquid

$$a = \frac{196.3\,Q}{K_d\ K_W\ K_V}\sqrt{\frac{SG_L}{P_1 - P_2}}$$

where :

$K_W = Correction\ \ factor\ \ for\ back - pressure$

$= 0.77\ \ for\ 41.6\ \ percent\ gauge\ back - pressure\ \ from$

$Figure\ 15$

$$a = \frac{196.3\,(2.38)}{(0.65)(0.77)(0.95)}\sqrt{\frac{0.63}{5647}}$$

$$= 10.4\ mm^2\ (0.016\ in^2)$$

10. Calculate Total Orifice Size

$$a_{TOTAL} = a_L + a_G$$
$$= 816.2 + 10.4$$
$$= 826.6 mm^2 (1.281 in^2) : Use\ valve\ size\ \ 'K'$$

11. Pilot Operated Valve

12. Calculate Orifice Size for Gas

$$a = \frac{555.79\,V\sqrt{T\;Z\;MW}}{C\;K_d\;P_1\;K_b}$$

$$a = \frac{555.79\,(52{,}000)\sqrt{(273+38)(0.75)(23.2)}}{(341.71)(0.92)(9198.3)(1)}$$

$$= 735.2\ mm^2\ (1.140\ in^2)$$

13. Calculate Orifice Size for Liquid

$$a = \frac{196.3\,Q}{K_d\;K_W\;K_V}\sqrt{\frac{SG_L}{P_1 - P_2}}$$

$$a = \frac{196.3\,(2.38)}{(0.65)(1)(0.95)}\sqrt{\frac{0.63}{5647}}$$

$$= 8.0\ mm^2\ (0.012\ in^2)$$

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14. Calculate Total Orifice Size

$$a_{TOTAL} = 735.2 + 8.0$$

$$= 743.2\ mm^2\ \left(1.152\ in^2\right) : Use\ valve\ size\ 'J'$$

15. Gas Subcritical Flow

Given:

V	=	Maximum gas flow rate	=	30,000 std m^3/hr
MW	=	Molecular weight of gas	=	23.2
Z	=	Compressibility factor	=	0.75
k	=	Ratio of specific heats	=	1.245
T	=	Flowing temperature	=	21°C
P_{set}	=	Set pressure	=	690 kPa
P_b	=	Back-pressure	=	410 kPa
K_d	=	Valve coefficient of discharge for conventional and bellows	=	0.975
K_d	=	Valve coefficient for pilot	=	0.92

Determine whether gas flow is critical or subcritical

Calculate orifice size for:

4. Conventional safety relief valve (bonnet vented to atmosphere)
5. Balanced bellows safety relief valve
6. Pilot operated valve

16. Subcritical Flow Example Problem

Determine whether gas flow is critical or subcritical

$$\gamma_c = \frac{P_{cf}}{P_1} = \left[\frac{2}{k+1}\right]^{\frac{k}{k-1}}$$

$$P_{cf} = (690 + 69 + 101.3)\left[\frac{2}{1.245+1}\right]^{\frac{1.245}{(1.245-1)}}$$

$$= 478\ kPa$$

P_{cf} is greater than the back-pressure of 517 kPa, so flow through relief valve is subcritical.

Permitted build-up back-pressure of 10 percent of P_{set} is 69 kPa, so total back- pressure = 410 + 69 = 479 kPa (G).

17. Conventional Safety Relief Valve (Vented Bonnet)

$$a = \frac{0.756\,V}{F_2\,K_d}\sqrt{\frac{ZT\,MW}{P_1\,(P_1 - P_2)}}$$

From Figure 14, for $r = P_2/P_1 = (410 + 69 + 101.3)/(690 + 69 + 101.3) = 0.67$, coefficient of subcritical flow $F_2 = 0.79$.

$$a = \frac{0.756\,(30{,}000)}{(0.79)(0.975)}\sqrt{\frac{(0.75)(273+21)(23.2)}{(860.3)(860.3 - 580.3)}}$$

$$= 4291.0\ mm^2\ (6.651\ in^2): Use\ valve\ size\ 'Q'$$

18. Balanced Bellows Safety Relief Valve

$$a = \frac{555.79\,V\sqrt{T\;Z\;MW}}{C\;K_d\;P_1\;K_b}$$

Assume K_b = 0.65 for this application. This value would normally be obtained from the manufacturer.

$$a = \frac{555.79\,(30{,}000)\sqrt{(273+21)(0.75)(23.2)}}{(341.71)(0.975)(860.3)(0.65)}$$

$$= 6401.1\ mm^2\ (9.922\ in^2) : Use\ valve\ size\ 'Q'$$

19. Pilot Operated Valve

$$a = \frac{0.756\,V}{F_2\;K_d}\sqrt{\frac{ZT\;MW}{P_1\,(P_1 - P_2)}}$$

$$a = \frac{0.756\,(30{,}000)}{(0.79)(0.92)}\sqrt{\frac{(0.75)(273+21)(23.2)}{(860.3)(860.3-580.3)}}$$

$$= 4547.5\ mm^2\ (7.049\ in^2) : Use\ valve\ size\ 'Q'$$

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Appendix C–Example Problems - Customary Units

20. Two-Phase Flow

Given:

V	=	Maximum gas flow rate	=	44 MMSCFD
MW	=	Molecular weight of gas	=	23.2
Z	=	Compressibility factor	=	0.75
k	=	Ratio of specific heats	=	1.245
T	=	Flowing temperature	=	100°F
P_{set}	=	Set pressure	=	1200 psig
P_b	=	Back-pressure	=	500 psig
Q	=	Liquid Rate	=	360 BPD
SG_L	=	Specific gravity of liquid (Water = 1)	=	0.63
K_d	=	Valve coefficient of discharge for conventional and bellows	=	0.975
K_d	=	Valve coefficient for pilot	=	0.92
K_d	=	Valve coefficient for liquid service	=	0.65
K_v	=	Viscosity correction factor	=	0.95

Determine whether gas flow is critical or subcritical.

Calculate orifice size for:

7. Conventional safety relief valve (bonnet vented to atmosphere)
8. Balanced bellows safety relief valve
9. Pilot operated valve

21. Two-Phase Flow Example Problem

Determine whether gas flow is critical or subcritical.

$$\gamma_c = \frac{P_{cf}}{P_1} = \left[\frac{2}{k+1}\right]^{\frac{k}{k-1}}$$

$$P_{cf} = (1200 + 120 + 14.7)\left[\frac{2}{1.245+1}\right]^{\frac{1.245}{(1.245-1)}}$$

$$= 742 \text{ psia}$$

P_{cf} is greater than the back-pressure of 515 psia, so flow through relief valve is critical.

22. Conventional Safety Relief Valve (Vented Bonnet)

23. Calculate Orifice Size for Gas

$$a = \frac{V\sqrt{T\ Z\ MW}}{6.32\ C\ K_d\ P_1\ K_b}$$

where :

$C = Gas\ constant\ based\ on\ ratio\ of\ specific\ heats\ C_P / C_V$

$$= \frac{341.22 + 342.19}{2} = 341.71,\ from\ Table\ 2$$

$K_b = Back\text{-}pressure\ correction\ factor$

$$= 1$$

$$V = (44)(10^6)\frac{ft^3}{day} \times \frac{day}{24\ hr} \times \frac{hr}{60\ min} = 30556\ \frac{ft^3}{min}$$

$$P_1 = (1200 + 120 + 14.7) = 1335\ psia$$

$$a = \frac{(30{,}556)\sqrt{(100 + 460)(0.75)(23.2)}}{6.32\ (341.71)(0.975)(1335)(1)}$$

$$= 1.073\ in^2\ :\ Use\ valve\ size\ 'J'$$

24. Calculate Orifice Size for Liquid

$$a = \frac{Q}{38\, K_d\, K_W\, K_V} \sqrt{\frac{SG_L}{P_1 - P_2}}$$

where :

$$Q = 360 \frac{barrels}{day} \times \frac{42\ gal}{barrel} \times \frac{day}{24\ hr} \times \frac{hr}{60\ min} = 10.5\ gpm$$

$$P_1 - P_2 = 1200 + 120 - 500 = 820\ psi$$

$$a = \frac{(10.5)}{38\,(0.65)(1)(0.95)} \sqrt{\frac{0.63}{820}}$$

$$= 0.012\ in^2$$

25. Calculate Total Orifice Size

$$a_{TOTAL} = a_L + a_G$$

$$= 0.012 + 1.073$$

$$= 1.085\ in^2 : Use\ valve\ size\ 'J'$$

26. Balanced Bellows Safety Relief Valve

27. Calculate Orifice Size for Gas

$$a = \frac{V\sqrt{T\ Z\ MW}}{6.32\ C\ K_d\ P_1\ K_b}$$

Determine K_b

$$Percent\ Gauge\ Back\text{-}Pressure = \frac{Back\text{-}Pressure,\ psig}{Set\ Pressure,\ psig} \times 100$$

$$= \frac{500\ (100)}{1200} = 41.6\ \ percent$$

$$K_b = 0.85\ \ from\ Figure\ 13\ with\ 10\ \ percent\ overpressure$$

$$a = \frac{30556\ \sqrt{(560)(0.75)(23.2)}}{6.32\ (341.71)(0.975)(1335)(0.85)}$$

$$= 1.262\ in^2$$

28. Calculate Orifice Size for Liquid

$$a = \frac{Q}{38\, K_d\, K_W\, K_V} \sqrt{\frac{SG_L}{P_1 - P_2}}$$

where :

$K_W = Correction\ factor\ for\ back\text{-}pressure$

$= 0.77\ for\ 41.6\ percent\ gauge\ back\text{-}pressure\ from\ Figure\ 15$

$$a = \frac{10.5}{38\,(0.65)(0.77)(0.95)} \sqrt{\frac{0.63}{820}}$$

$$= 0.016\ in^2$$

29. Calculate Total Orifice Size

$$a_{TOTAL} = 0.016 + 1.262$$

$$= 1.278\ in^2\ : Use\ valve\ size\ 'K'$$

30. Pilot Operated Valve

31. Calculate Orifice Size for Gas

$$a = \frac{V\sqrt{T\ Z\ MW}}{6.32\ C\ K_d\ P_1\ K_b}$$

$$a = \frac{(30{,}556)\sqrt{(560)(0.75)(23.2)}}{6.32\,(341.71)(0.92)(1335)(1)}$$

$$= 1.137\ in^2$$

32. Calculate Orifice Size for Liquid

$$a = \frac{Q}{38\ K_d\ K_W\ K_V}\sqrt{\frac{SG_L}{P_1 - P_2}}$$

$$a = \frac{10.5}{38\,(0.65)(1)(0.95)}\sqrt{\frac{0.63}{820}}$$

$$= 0.012\ in^2$$

33. Calculate Total Orifice Size

$$a_{TOTAL} = 0.012 + 1.137$$

$$= 1.149\ in^2 : Use\ valve\ size\ 'J'$$

34. Gas Subcritical Flow

Given:

V	=	Maximum gas flow rate	=	25 MMSCFD
MW	=	Molecular weight of gas	=	23.2
Z	=	Compressibility factor	=	0.75
k	=	Ratio of specific heats	=	1.245
T	=	Flowing temperature	=	70°F
P_{set}	=	Set pressure	=	100 psig
P_b	=	Back-pressure	=	60 psig
K_d	=	Valve coefficient of discharge for conventional and bellows	=	0.975
K_d	=	Valve coefficient for pilot	=	0.92

Determine whether gas flow is critical or subcritical.

Calculate orifice size for:

10. Conventional safety relief valve (bonnet vented to atmosphere)
11. Balanced bellows safety relief valve
12. Pilot operated valve

35. Subcritical Flow Example Problem

Determine whether gas flow is critical or subcritical

$$\gamma_c = \frac{P_{cf}}{P_1} = \left[\frac{2}{k+1}\right]^{\frac{k}{k-1}}$$

$$P_{cf} = (100 + 10 + 14.7)\left[\frac{2}{1.245+1}\right]^{\frac{1.245}{(1.245-1)}}$$

$$= 69.3 \ psia$$

P_{cf} is greater than the back-pressure of 517 kPa, so flow through relief valve is subcritical.

Permitted build-up back-pressure of 10 percent of P_{set} is 10 psi, so total back- pressure = 60 + 10 = 70 psig.

36. Conventional Safety Relief Valve (Vented Bonnet)

$$a = \frac{V}{4645.2\, F_2\, K_d}\sqrt{\frac{ZT\, MW}{P_1\,(P_1 - P_2)}}$$

where :

$$V = (25)(10^6)\frac{ft^3}{day} \times \frac{day}{24\ hr} \times \frac{hr}{60\ min} = 17{,}361\frac{ft^3}{min}$$

From Figure 14, for $r = P_2/P_1 = (60 + 10 + 14.7)/(100 + 10 + 14.7) = 0.68$, coefficient of subcritical flow $F_2 = 0.80$.

$$a = \frac{(17{,}361)}{(4645.2)(0.80)(0.975)}\sqrt{\frac{(0.75)(460+70)(23.2)}{(124.7)(124.7 - 84.7)}}$$

$$= 6.651\ in^2 : Use\ valve\ size\ 'Q'$$

37. Balanced Bellows Safety Relief Valve

$$a = \frac{V\sqrt{T\ Z\ MW}}{6.32\ C\ K_d\ P_1\ K_b}$$

Assume K_b = 0.65 for this application. This value would normally be obtained from the manufacturer.

$$a = \frac{(17{,}361)\sqrt{(460+70)(0.75)(23.2)}}{6.32\,(341.71)(0.975)(124.7)(0.65)}$$

$$= 9.769\ in^2 : Use\ valve\ size\ 'Q'$$

38. Pilot Operated Valve

$$a = \frac{V}{4645.2\ F_2\ K_d}\sqrt{\frac{ZT\ MW}{P_1\,(P_1 - P_2)}}$$

$$a = \frac{(17{,}361)}{(4645.2)(0.80)(0.92)}\sqrt{\frac{(0.75)(460+70)(23.2)}{(124.7)(124.7-84.7)}}$$

$$= 6.905\ in^2 : Use\ valve\ size\ 'Q'$$

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Safety Shutdown Systems

EPT 05-T-11

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Version 0

Table of Contents

1. Scope 6

2. References 6

2.1. MEPS–Mobil Engineering Practices 6

2.2. API–American Petroleum Institute 6

2.3. CFR–U.S. Code of Federal Regulations 6

2.4. Chilton 6

2.5. NFPA–National Fire Protection Association 7

3. System Selection 7

3.1. Design 7

3.2. Circuit Types 8

4. Pneumatic Systems 9

4.1. Design 9

4.2. System Logic 12

4.3. Bypass Circuits 14

4.4. Lockout and Manual Resets 16

4.5. First-Out Indicator Circuits 18

4.6. ESD/Fire 21

4.7. Alarm Function 23

4.8. Interposing Devices 23

4.9. Quick Bleed 24

4.10. Timing/Bypass Circuits 26

5. Electrical Systems 27

5.1. Design 27

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5.2. Sensing Devices 28
5.3. Relays 28
5.4. Annunciators 29
5.5. System Logic 30
6. Electronic Systems 35
6.1. 35
6.2. 36
7. Safety Analysis Concepts 36
7.1. General 36
7.2. Hazard Analysis 37
7.3. Developing a Safe Process 43
7.4. Primary Defense 45
7.5. Failure Mode Effect Analysis–FMEA 46
7.6. Modified FMEA Approach 50
7.7. API Recommended Practice 53
7.8. Hazards Analysis 56

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Table of Figures

Figure 1: Schematic Diagram of Two Possible Options for Pneumatic Safety Shutdown System Control Panels....11

Figure 2: Schematic Depicting Logic Design for Simple System, per API RP 14C 13

Figure 3: Schematic Depicting Shutdown Logic Containing Single-Circuit Bypasses, per API RP 14C....15

Figure 4: Schematic Depicting Shutdown Logic Containing Bypass of all Devices Protecting a Single Process Component, per API RP 14C....16

Figure 5: Schematic Depicting Shutdown Logic with Manual Reset Relays Installed for Each Logic Loop 17

Figure 6: Pneumatic Indicators Depicting Typical Indicator Flag Showing Red-and-White Striped Tape in the Window When There is No Pressure, and a Solid Green Tape with Pressure; Alternate Tapes Showing "Open" and "Closed" for Same Conditions (Courtesy of Amot Controls Corp.) 19

Figure 7: Pneumatic Indicating Relay (Courtesy of Amot Controls Corp.) 20

Figure 8: Quick Exhaust Valve Used in Continuous Loop Facility ESD System 21

Figure 9: Schematic Depicting Shutdown Logic from Figure 5 with ESD and Fusible Loop Control Logic Added, per API RP 14C....23

Figure 10: Typical Pneumatic Quick Exhaust Valve Used to Decrease Response Time for Shutdown Devices (Courtesy of Sigma Enterprises, Inc.) 25

Figure 11: Schematic Showing Application of a Quick Exhaust Valve 26

Figure 12: Typical Variable Restrictor with Integral Check Valve (Courtesy of Deltrol and Air-Dreco Inc.)....27

Figure 13: Electrical Annunciators (Courtesy of Ametek, Inc., Panalarm Division, Skokie, IL)....30

Figure 14: Bypass Circuit....31

Figure 15: Shutdown Logic with Total Circuit Bypass....32

Figure 16: Shutdown Logic with Process Train System Bypass 33

Figure 17: Shutdown Logic 34

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Figure 18A: Shutdown Logic for Typical PLC (Connection Diagram) 34

Figure 18B: Shutdown Logic (Operational Diagram) 35

Figure 19: Hazard Tree Developed for Analysis of Walking in an Office Corridor 38

Figure 20: Hazard Tree Developed for a Generalized Production Facility 40

1. Scope

This tutorial covers system types, selection, and analysis concepts used in the design and evaluation of safety shutdown systems.

2. References

The following standards and industry publications shall be considered a part of this EPT. Refer to the latest editions unless otherwise specified herein.

2.1. MEPS–Mobil Engineering Practices

MP 32-P-07	Safety Interlock Systems and Alarms
MP 32-P-10	Wellhead Shutdown and Hydraulic Control Panels
MP 70-P-03	Hazard Assessment

2.2. API–American Petroleum Institute

API RP 14C	Recommended Practice for Analysis, Design, Installation, and Testing of Basic Surface Safety Systems for Offshore Production Platforms Fifth Edition; Errata - 1994
API RP 14J	Recommended Practice for Design and Hazards Analysis for Offshore Production Facilities First Edition

2.3. CFR–U.S. Code of Federal Regulations

30 CFR 250	Mineral Management Service, Department of the Interior, Subchapter B - Offshore

2.4. Chilton

CHILTON	Instruments Engineer's Handbook (2 Volumes): Process Measurement and Process Control

2.5. NFPA–National Fire Protection Association

NFPA 70	National Electrical Code 1996 Edition Errata #1; Tentative Interim Amendment 1996
NFPA 493	Intrinsically Safe Apparatus, Hazardous Locations

3. System Selection

3.1. Design

3.1.1.

The first step in designing a shutdown system is determining whether to use an electric or a pneumatic system. The most common systems are a combination of pneumatic and electric. Electric/electronic systems are common, however, and they offer high reliability. These systems are designed using a system of relays or multi-redundant microprocessor-based systems. The shutdown system shall be designed to provide the necessary logic, interlocks, bypass systems, shutdown signals, and alarms so that abnormal conditions detected by process sensors will perform the expected alarm or shutdown functions.

3.1.2.

In addition, the system shall be designed for “fail-safe” operation. This means that, in the event of any component failure or loss of system power, the shutdown system will operate and shut down the process. This is accomplished pneumatically by using a pressurized system for detection, holding all valves and similar devices in the operating mode. Upon detecting a malfunction, the sensing device vents pressure and the system shuts down. In an electrical/electronic system, the contacts of the sensing devices are closed in the operating mode, and the relays or end devices are energized to run. The opening of the contacts breaks the electrical circuit, de-energizing the relays or end devices, and, consequently, shutting down the system.

3.1.3.

Since both types of systems need power to operate, a leak in the pneumatic system or wire break in the electrical system will cause a shutdown.

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3.1.4.

The design concepts and typical circuit devices discussed in this tutorial are by no means all-inclusive. There are many ways to design circuits to perform a specified logic function, and many different types of devices can be used in these circuits. Also, manufacturers' devices differ from each other in detail of design. However, the circuits and devices discussed are meant to be illustrative of common designs and of concepts that can be extended to evaluate any design or device.

3.2. Circuit Types

The logic for any shutdown system design consists of stringing together a number of individual circuits arranged in a hierarchical order.

3.2.1. Alarm Only

The alarm circuit provides the lowest level of protection. At this level, process conditions are monitored and impending problems are brought to the attention of the operator. This level is used only where the operator has time to take corrective action and remedy the problem.

3.2.2. Selected Item Shutdown

The next level of protection is provided by a selective shutdown circuit that causes a shutdown of individual pieces of equipment or process vessels. Often it is used when parallel units or pieces of equipment operate and the shutdown of one would not be detrimental to the process. An example in a production facility is the test separator, which, if shut down, would not affect the overall operation of the facility. Thus, there is no need to shut in the total facility when a sensor in the test separator indicates a potentially unsafe condition. It is sufficient to shut in the inlet to the test separator or the producing well to the test separator to isolate the test separator from the process.

3.2.3. Process Train Shutdown

The third protection level is a process train shutdown. At this level, all of the process systems affected by the sensed process upset or equipment failure would be shut down; for example, an intermediate pressure production separator, which gets production directly from wells as well as liquid from a high-pressure separator. A malfunction in the intermediate-pressure separator will shut down the inlet to both the intermediate-pressure separator and the high-pressure separator but will not necessarily shut down the low-pressure separator and other downstream components.

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3.2.4. Process System Shutdown

The next level of protection is a complete process system shutdown. The whole facility is shut down because of a sensed malfunction in equipment receiving input from all streams. For example, if a malfunction is detected in a low-pressure separator that received liquid from all the production separators, it shall be necessary to shut in all feed to the facility to shut in flow to the low-pressure separator.

3.2.5. ESD/Fire

The highest level of protection is Emergency Shutdown (ESD). At this level, all process systems are shut down. All incoming/outgoing lines are isolated, and, quite often, all support equipment is shut down. These shutdowns usually result from the detection of catastrophic conditions such as fire and major gas or oil leaks, or operator decision. Also, in the case of fire, it might be desirous to automatically start fire pumps, activate deluge systems, etc. Each shutdown level is interlocked with the next lower level. That is, ESD will initiate process system shutdown, process system shutdown will initiate process train shutdown, and so on. The lowest level of the system, alarm only, stands alone.

4. Pneumatic Systems

4.1. Design

4.1.1.

Pneumatic systems are common on most small offshore production facilities and small inland facilities. Since these types of facilities also employ pneumatic process control systems, the source of operating medium for a pneumatic shutdown system is readily available. The supply shall be at a pressure (normally 690 to 860 kPa [100 to 125 psig]) adequate for the operation of any shutdown valves in the system. The supply pressure to each individual sensor is normally regulated down to 140 to 210 kPa (20 to 30 psig).

4.1.2.

Air shall be filtered and dried to remove solids and moisture that can condense and plug small openings in the instrumentation. Filtered natural gas is also commonly used in lieu of air.

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4.1.3.

All sensors, instrument valves, etc., are designed to move to the vent position when supply pressure is lost. All shutdown valves and alarms are designed to return to the shut-in or alarm position on loss of signal. Thus, the system is designed to "fail safe".

4.1.4.

If a pneumatic system is chosen, it is necessary to choose either to use a single central panel for all logic and indication or to use local panels feeding a central panel. Figure 1 shows the two options in block diagram form.

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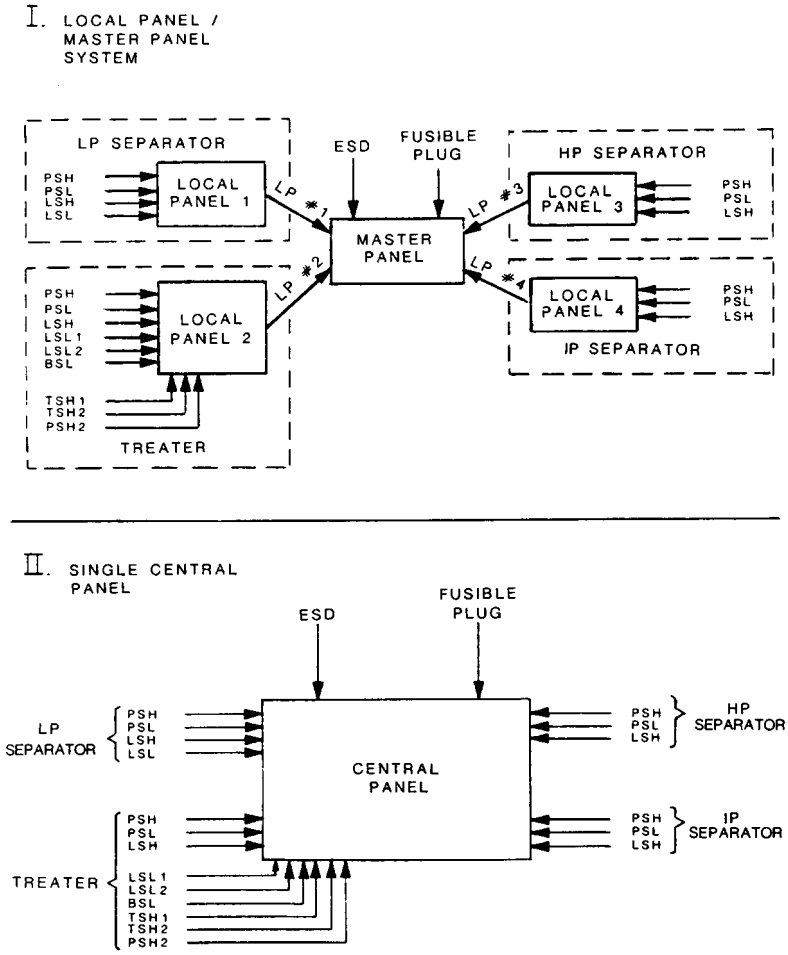

Figure 1: Schematic Diagram of Two Possible Options for Pneumatic Safety Shutdown System Control Panels

4.1.5.

On complete multilevel facilities, most operators use the local panel approach. All signals from a piece or group of equipment are sent to a local panel with first-out indication. The local panels send a single signal to the master panel, with one indicator to tell the operator which local panel initiated the shutdown or alarm. In most such systems the ESD and fusible plug logic are contained in the master panel.

4.1.6.

When a shutdown or alarm occurs, the operator first goes to the master panel to see which local panel initiated the action, then to the local panel to determine which end device was the first to trip.

4.1.7.

This system minimizes tubing run length and, thus, tends to cost less for multilevel facilities and for facilities requiring five or more local panels. It is also more easily adaptable to future facility additions or process changes.

4.1.8.

To aid in troubleshooting, it is desirable to install pressure gauges in the panel face to indicate supply pressure, ESD loop pressure, fusible loop pressure, and pressure on each of the outputs leaving the panel. If a PSH or PSL is mounted in the panel, a pressure gauge shall indicate the process pressure being monitored.

4.2. System Logic

4.2.1.

The first step in developing a system logic design is development of a function matrix chart. The basics of system logic design involve grouping sensors according to the function they perform. All sensors performing the same function are placed together in series so that loss of pressure from any one sensor causes the loss of output from the group to the function. (See Figure 2, which shows the logic for a simple system.)

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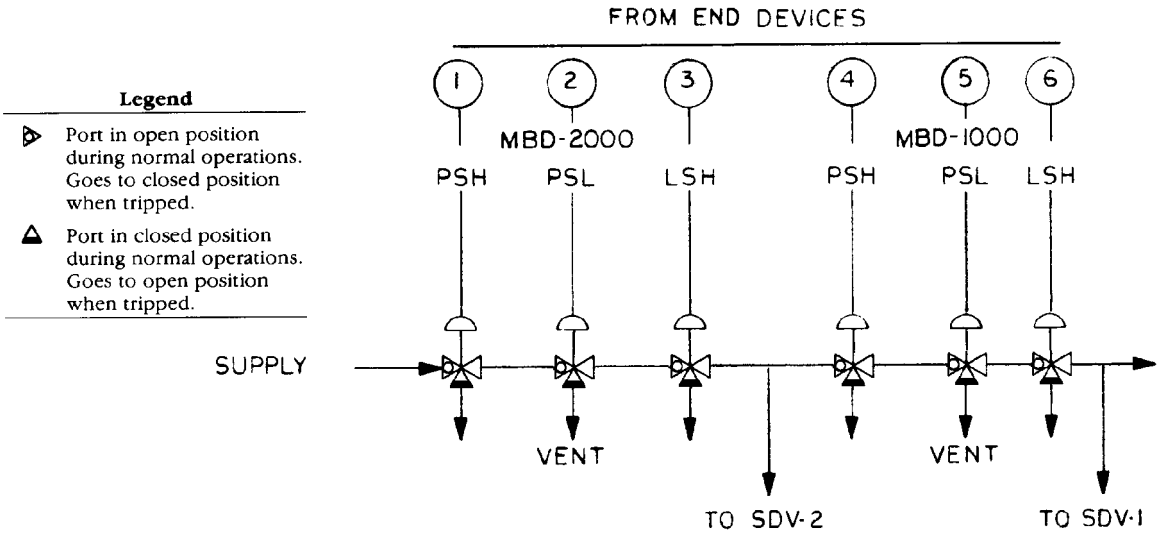

Figure 2: Schematic Depicting Logic Design for Simple System, per API RP 14C

4.2.2.

Each end device is connected to a three-way valve. As long as the end device is satisfied, it allows its supply pressure to go to the diaphragm of its three-way valve, and supply pressure goes through the three-way valves to the Shutdown Valve (SDV), which then is in the operating mode. The three-way pilot operated valve is called “block and bleed relay”. When this relay is in service, the supply and output ports are common, and the vent port is closed. When the relay is out of service, the supply port is isolated, and the output port and vent ports are common.

4.2.3.

If any of sensors 1 to 3 trips, it blocks the supply to the diaphragm of the three-way valve and bleeds the pressure off the three-way valve's diaphragm, causing the three-way valve to block the supply and vent all downstream tubing. The supply going to SDV-1 and SDV-2 is vented. On loss of supply, both valves return to the safe position.

4.2.4.

If any of sensors 4 to 6 trips, the supply to SDV-2 stays intact, but SDV-1 loses its supply and returns to a safe position.

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4.3. Bypass Circuits

Process systems or equipment have start-up conditions that shall be bypassed in order to put that system or piece of equipment into service. These conditions are most often "low" conditions, such as low levels and low pressures. An example might be the low lube oil pressure switch on a compressor shutdown sequence, which shall be bypassed during startup until the compressor is operating the lube oil pump. In addition, bypasses are necessary to allow testing and maintenance without shutting down the process or equipment.

4.3.1. Types

1. There are two types of bypasses. The first, a manual bypass, is the most common, usually consisting of a three-way valve on the panel front, with tags indicating the bypass position and the in-service position. This type of bypass always shall be located so that the condition of the bypass circuit can be determined at a single glance. Sometimes when these bypasses are located on remote or slave panels, an indicator is placed in the master panel to give indication of the bypass condition.

2. The second type of bypass is an automatic-reset type, which requires manual holding in bypass. If released, the bypass circuit shall automatically return to the in-service position. Alternatively, it may incorporate a timing circuit that will automatically place the system back in service after a preset period of time. Manually held automatic-reset bypasses are most often used in ESD/fire circuits. Frequently, this type of bypass is labeled "Press to Test". Time-controlled automatic-reset bypasses are most often used in engine, pump, or compressor panels for which some period of time is required after start-up initiation before operating conditions can be expected to stabilize.

4.3.2. Configuration

1. Bypasses can be configured to bypass single devices, a complete group of devices protecting a process component, all devices protecting an entire process train, or all devices in the complete system. Of these, the most common is the single device or circuit bypass. Figure 3 is a schematic of the shutdown logic containing single circuit bypasses. For example, the PSL on MBD-1000 and MBD-2000 can be bypassed to allow the opening of SDV-1 and SDV-2 without affecting the other shutdown circuits. Refer to the basics tutorial (EPT 05-T-01) for specific device operation.

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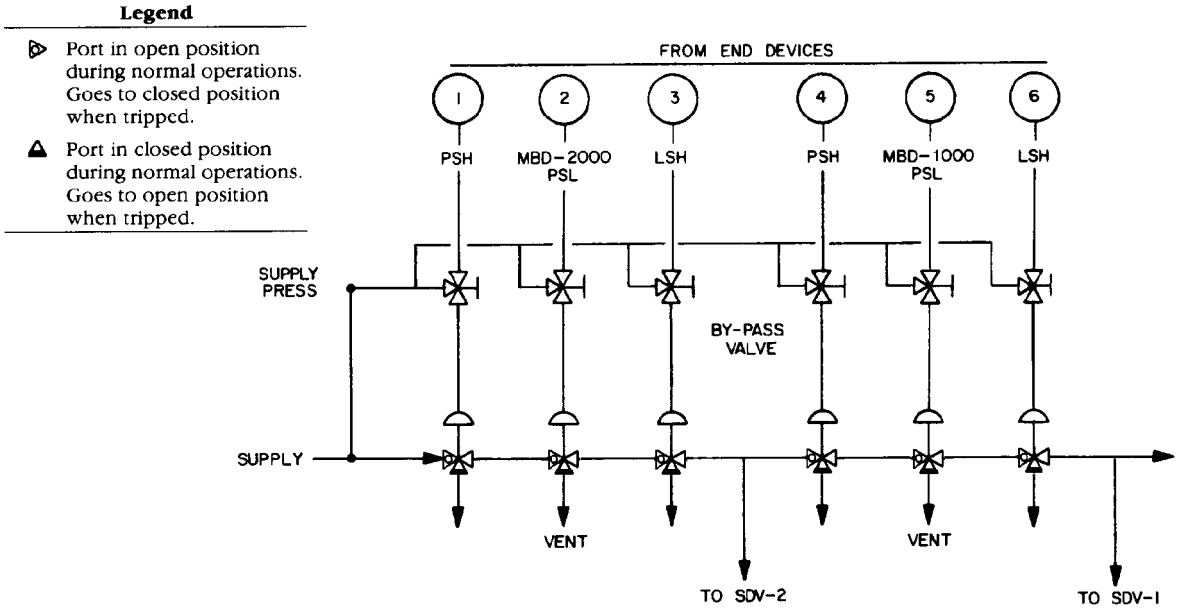

Figure 3: Schematic Depicting Shutdown Logic Containing Single-Circuit Bypasses, per API RP 14C

2. The next most common circuit is that which bypasses all devices protecting a single process component. Figure 4 shows shutdown logic with this configuration: when SDV-1 or SDV-2 is placed in bypass, all signals from MBD-1000 and MBD-2000 that could activate it are bypassed. While this is less expensive than using single circuit bypasses, in order to do maintenance on any one device (PSH, PSL or LSH), it is necessary to bypass all other safety items that could activate the valve at the same time. However, it is possible to keep SDV-2 in service while SDV-1 is bypassed.

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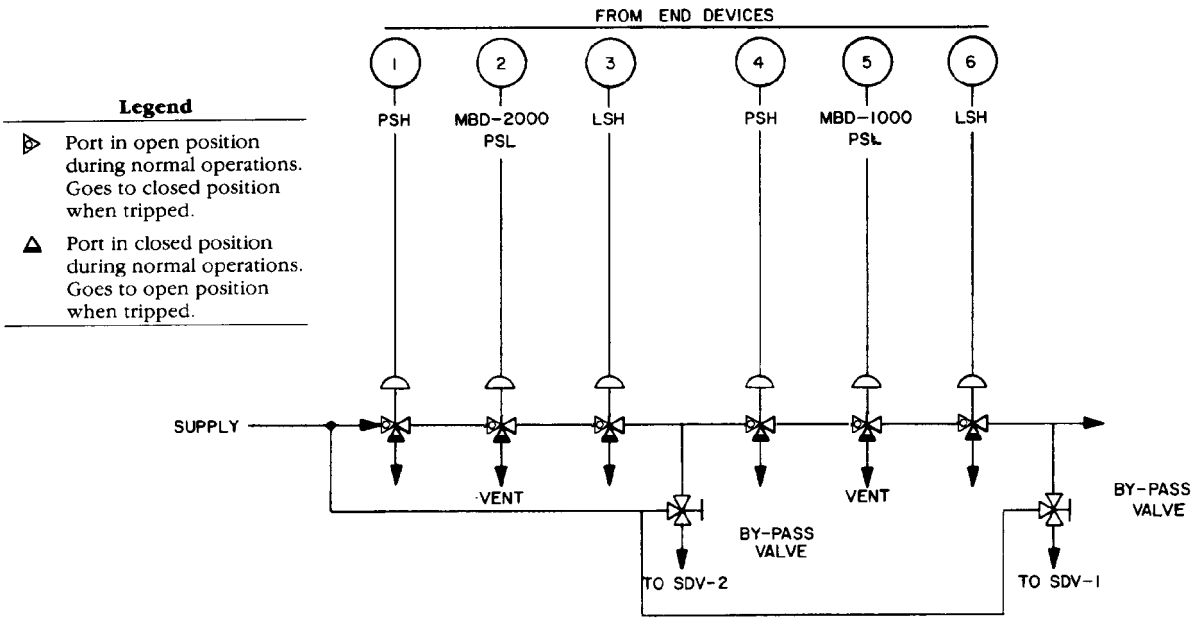

Figure 4: Schematic Depicting Shutdown Logic Containing Bypass of all Devices Protecting a Single Process Component, per API RP 14C

3. It is possible to perform testing or maintenance on any of the inputs (PSH, PSL or LSH) and on any of the outputs (SDV-1 or SDV-2) without affecting the operation of the other inputs or outputs.

4. It must be stressed that a bypass inactivates a safety item required to provide an adequate level of protection, so the configuration and location of bypasses shall be given careful thought. A bypass that is not easily seen is a bypass that can easily be forgotten. Consideration shall be given to having separate but parallel alarm and shutdown circuits with independent bypasses. In such a design, the alarm circuit could be left in operation when the shutdown circuit is bypassed for testing.

4.4. Lockout and Manual Resets

4.4.1.

Almost all safety shutdown/alarm systems have a lockout feature that keeps the system from automatically changing and resetting itself. An operator shall pull a manual reset to provide supply to open a shutdown valve or to send a command to do so from a remote location.

4.4.2.

For example, in Figure 5, if there is a pressure surge in separator MBD-1000, the PSH shall trip, closing SDV-1, and the SDV will shut in. The pressure

will then decline in MBD-1000, and the PSH will clear. Without a lockout capability, SDV-1 will then reopen automatically, and the wells will surge into the separator. If the cause of the PSH is a partially blocked gas outlet (failure of a pressure control valve), then the wells shall continue to cycle until an operator takes corrective action. With lockout capability, SDV-1 will remain closed even after the PSH has cleared. An operator will then have to manually reset MR No. 2 to reestablish pressure to the SDV before the wells can start to produce again. Refer to the basics tutorial (EPT 05-T-01) for device specific details.

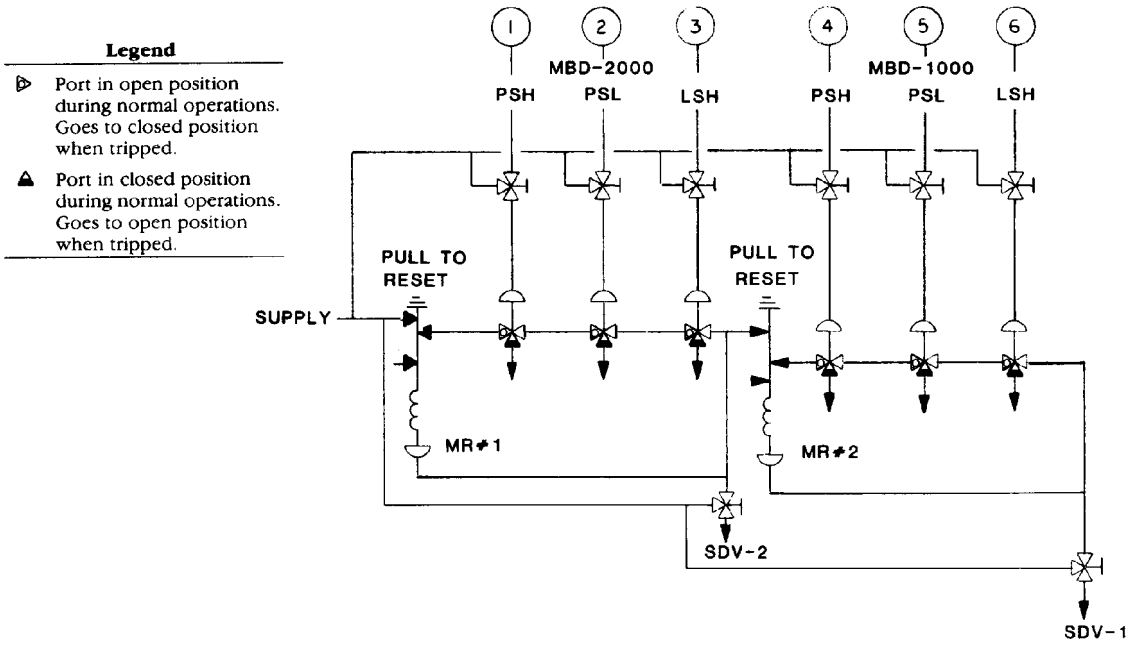

Figure 5: Schematic Depicting Shutdown Logic with Manual Reset Relays Installed for Each Logic Loop

4.4.3.

In Figure 5, manual reset relays are installed for each logic loop. When the output to an SDV is bled off by tripping one of the process sensors, the pressure on the diaphragm of the reset relay is also bled off. This causes the relay to move to a fail position, blocking the supply to the loop and venting the loop.

4.4.4.

As long as the reset relay is in this position, it shall block supply from going to the SDV, even if pressure is restored to the process port of the main logic three-way valve that was initially tripped. The reset relay can be activated

only by manually pulling it out, allowing pressure to pass through the three-way valves and eventually to the diaphragm of the relay itself.

4.4.5.

The manual reset valve is normally spring-loaded so that an operator must hold it while the system is energized, eliminating the possibility that the valve can be accidentally left in the reset position, effectively bypassing the shutdown sensors.

4.4.6.

It is possible to modify the reset valve so that it is held in the reset position by a signal sent from a remote location. The signal can be initiated manually from the remote location, and it switches off on a time cycle so that the reset valve cannot be accidentally left in the reset position, thus effectively bypassing the sensor.

4.5. First-Out Indicator Circuits

4.5.1.

Most production facilities are so complex that the immediate cause of a shutdown is not always clear. In a system such as the one shown in Figure 1, usually the lowest-numbered three-way valve ("indicator") that is in the vent position is associated with the sensor that initiated the shutdown. However, this may not always be the case. For example, suppose the H.P. Separator shuts in on LSH. If the back-pressure valve does not seal completely, with no inflow to the vessel, the pressure eventually shall bleed off and the PSL will trip. An operator investigating the shutdown at this point shall conclude that it was caused by a sensed PSL and not an LSH. If this is an unattended location, it is possible that, by the time an operator arrives, the instrument gas supply might be at a pressure low enough to have caused any number of three-way valves to trip.

4.5.2.

This situation can be avoided by using a "first-out indicator". A first-out indicator is a three-way valve designed to provide a signal when it is tripped and there is pressure at its supply port. Any indicator in the loop downstream of the first-out signal that is subsequently tripped will not show a signal, because its supply shall be vented. A subsequently tripped upstream valve may show a false signal if it is tripped when it still has pressure at its supply port. For this reason, it becomes necessary to use a lockout relay, as in Figure 5.

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4.5.3.

Pneumatic indicators show the status of individual components in the pneumatic shutdown system. Indicators are available in many configurations, such as pop out indicator, bull's-eye window, etc. The most common type is a circular window with a colored indicator tape behind it. The indicator (Figure 6) shows red with no pressure in the system and green with pressure. In most pneumatic systems, the pneumatic indicator is combined with a pneumatic relay that allows the system to be designed as a "first-out" system.

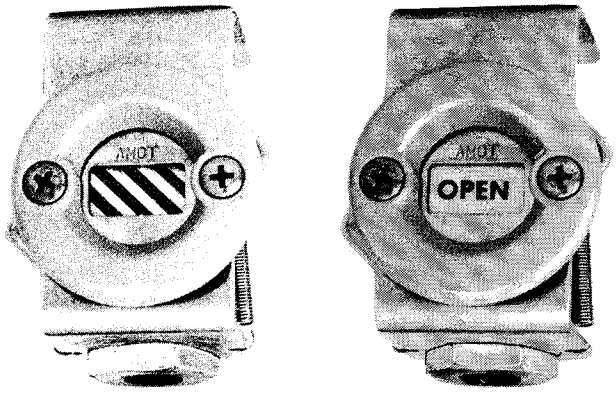

Figure 6: Pneumatic Indicators Depicting Typical Indicator Flag Showing Red-and-White Striped Tape in the Window When There is No Pressure, and a Solid Green Tape with Pressure; Alternate Tapes Showing "Open" and "Closed" for Same Conditions (Courtesy of Amot Controls Corp.)

4.5.4.

In a "first-out" system, the first system component that trips will cause its shutdown indicator to turn red, while all other indicators in the system shall stay green. Consequently, the operator can determine the initial cause of the shutdown (see Figure 7).

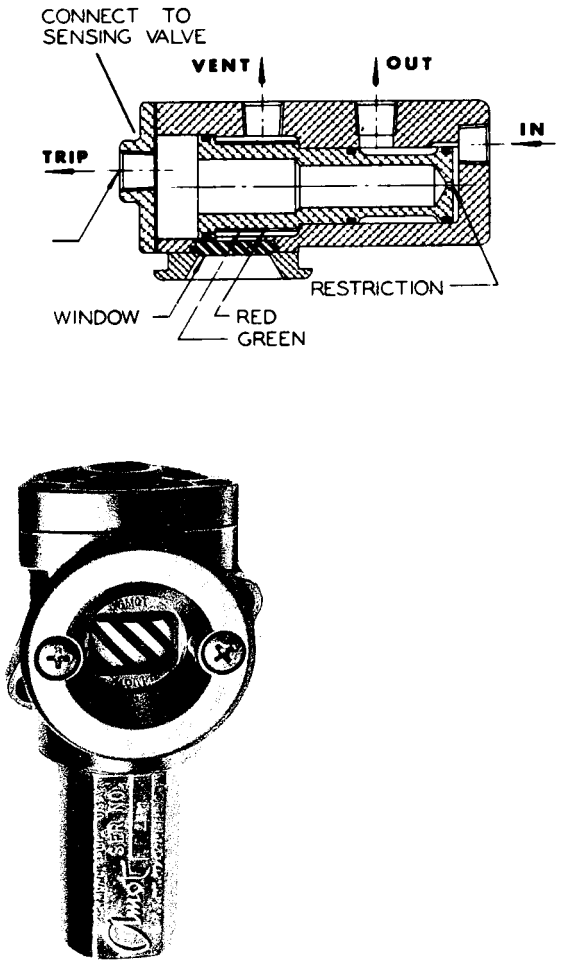

Figure 7: Pneumatic Indicating Relay (Courtesy of Amot Controls Corp.)

4.5.5.

When the sensing device trips, the air is vented off the large-diameter piston, and the supply pressure forces the indicator into the red position. This shift of the internal piston connects the OUT port to the VENT port. All pressure downstream of the relay is vented, and the IN port is blocked from the OUT port. Since there is still pressure on the trip port of the downstream indicators, their pistons will stay to the right and indicate “green”. The lockout relay that is part of the supply circuit (MR No. 1 and MR No. 2 of Figure 11) vents supply from the upstream indicators and keeps them from moving from green to red if their sensing valves subsequently trip.

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4.6. ESD/Fire

4.6.1.

The facility ESD/Fire system is a continuous loop with quick exhaust valves (see Figure 8) located at strategic positions. A quarter-turn ball valve also can be used for ESD service.

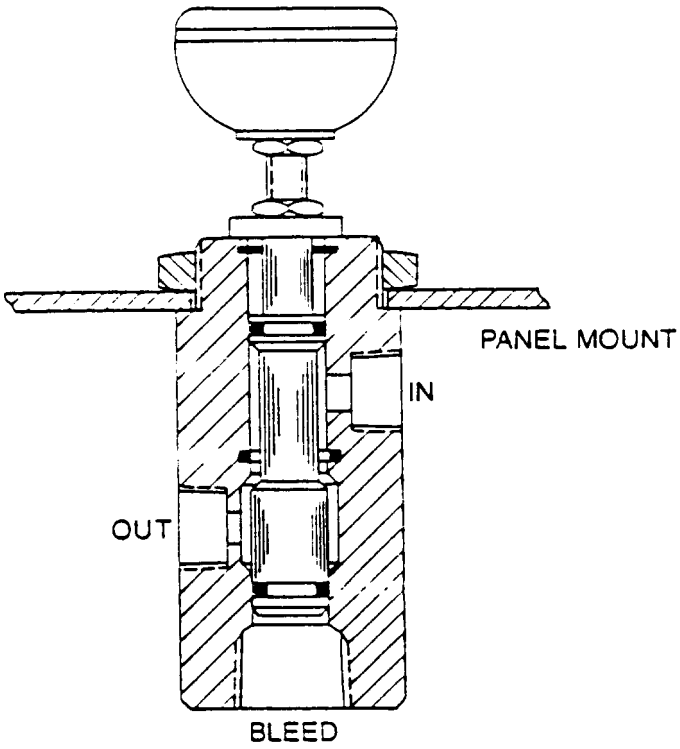

Figure 8: Quick Exhaust Valve Used in Continuous Loop Facility ESD System

4.6.2.

As used here, “fire systems” refers to fusible plug loops, where the fusible plugs are temperature-sensitive pneumatic valves that bleed off the air pressure in a loop when the plug melts.

4.6.3.

The manual valve shown in Figure 8 is a pull-to-activate valve that remains in the last position in which it is placed. Manually pulling the handle causes the inlet port to be blocked and the outlet to be connected to the bleed port, thereby depressuring the loop. See Figure 10 for an automatic quick exhaust device.

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4.6.4.

The most common sensors for fire are “fusible plugs”, typically tubing tees inserted into a pressurized loop. The outlet of the tee is blocked with a compound designed to melt at a specified temperature (normally 74 or 107°C, or 165 or 225°F). When any plug in the loop is exposed to this temperature, the material melts, venting the pressure in the loop; thus, 74°C (160°F) plugs shall be used for most applications. The higher-temperature plugs shall be employed around heaters, engines, and turbines to minimize the possibility of accidental tripping.

4.6.5.

Because of the number of tubing fittings in a typical ESD and fusible loop system, pressure leakage can be expected. For this reason, the system is always set up with a valve that enables the system to be charged quickly initially and a fixed orifice that allows a small amount of make-up air into the system. The system charge valve is spring-loaded so that it cannot be accidentally left open. Figure 9 shows Figure 5 with ESD and fusible loop control logic added.

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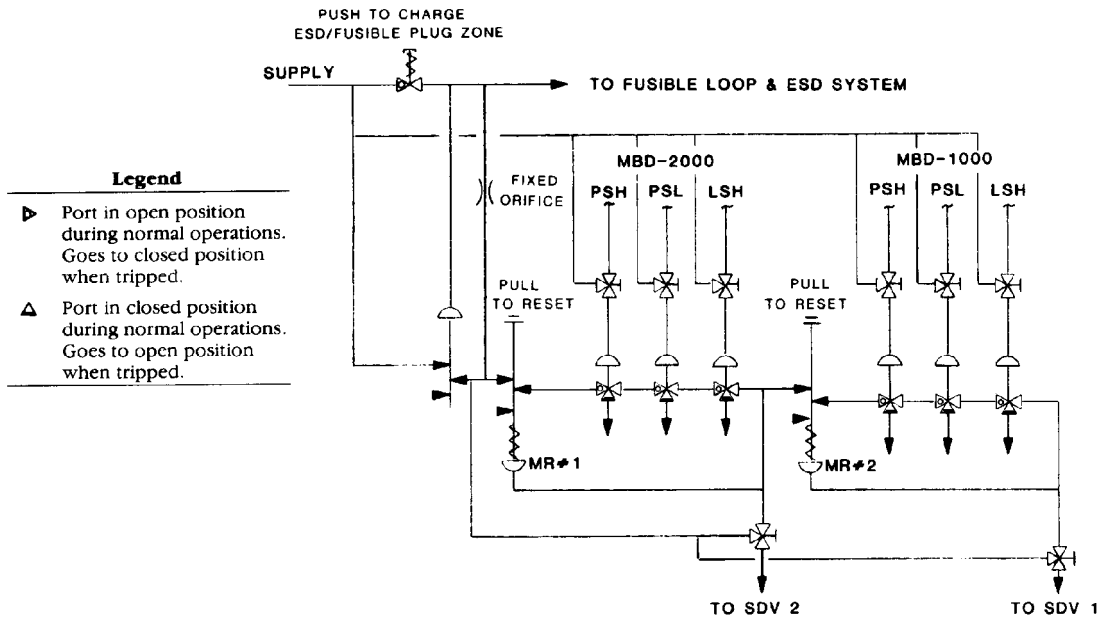

Figure 9: Schematic Depicting Shutdown Logic from Figure 5 with ESD and Fusible Loop Control Logic Added, per API RP 14C

4.7. Alarm Function

It is necessary to add an additional relay loop for all alarm functions so that a signal can be sent to a horn, light, or remote telemetry system. Normally this is the last loop in the system so that any shutdowns also activate the alarm.

4.8. Interposing Devices

4.8.1.

The normal operating pressure for a pneumatic system is 140 to 345 kPa (20 to 50 psig). Shutdown valve operators usually require a higher pressure than this, so it is necessary to provide an interposing device that will accept the low-pressure signal and provide the higher pressure for the operator. This is accomplished by using a spool valve. These valves can be obtained in a variety of porting arrangements, but typically three-way or five-way is used. When the signal from the shutdown system is applied to the piston end of the valve, the spool will shift, connecting the supply port to the output port of the valve. When the signal is removed from the piston, the spring at the other end of the piston will shift it in the opposite direction. The supply port is blocked, and the output port is connected to the vent port, depressurizing the

valve actuator. If the valve actuator is double-acting, requiring supply to operate it in both directions, then a five-port valve shall be used.

4.8.2.

Pressure switches are used to provide an electric signal similar to those required for telemetry or shutdown of electrical equipment. Solenoid valves are used as an electrical-to-pneumatic interposing device.

4.9. Quick Bleed

4.9.1.

A pneumatic shutdown system is inherently slow in operation, since its basic operational method is the venting of a pressured system. Consequently, the larger the volume to be vented, the slower the response. Quick-exhaust devices are used to decrease the response time. A typical pneumatic quick exhaust is shown in Figure 10.

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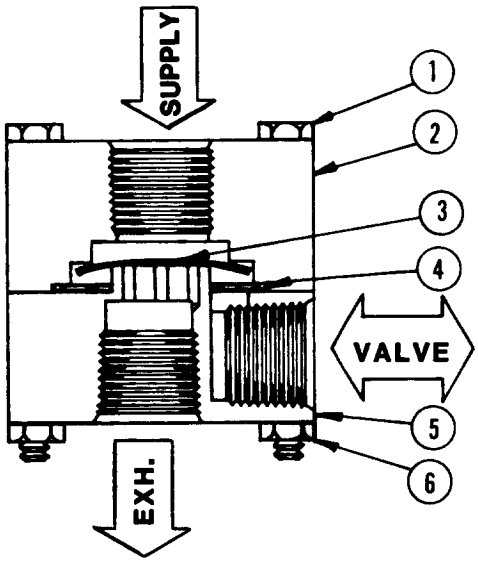

PARTS LIST

*	1	Hex Head Bolts
	2	Upper Body
*	3	Flapper Seal
*	4	O-Ring
	5	Lower Body
*	6	Hex Nuts

* Indicates parts included in Repair Kit.

Figure 10: Typical Pneumatic Quick Exhaust Valve Used to Decrease Response Time for Shutdown Devices (Courtesy of Sigma Enterprises, Inc.)

4.9.2.

In the rest position, the diaphragm sits on the exhaust port. As the control air is supplied to the inlet port, the diaphragm's outer edge is deflected, allowing air to pass to the cylinder port and operate the valve. As the inlet pressure is relieved, the diaphragm snaps off the exhaust port, closing the inlet port and allowing quick evacuation of the air from the output line through the large-diameter vent port. When the output air is exhausted, the diaphragm returns to the rest position.

4.9.3.

The quick exhaust can be used to speed up the shutdown system response by connecting the cylinder port of the quick bleed to the line being vented, and the output of the relay sensor to the inlet of the quick exhaust. When the relay sensor is tripped, the signal pressure to the quick exhaust decreases, and the output from the quick exhaust vents rapidly. A typical application of

quick exhausts is shown in Figure 11. Venting time of the system also may be improved by using check valves in the segments of the pneumatic system that need not be depressed to activate a particular relay or valve.

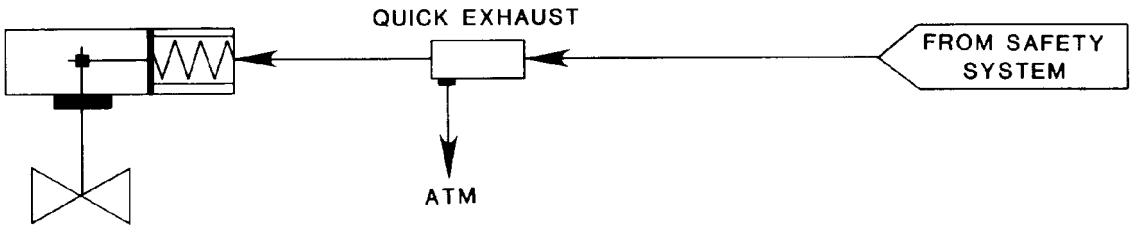

Figure 11: Schematic Showing Application of a Quick Exhaust Valve

4.10. Timing/Bypass Circuits

In pneumatic circuits, timing is achieved by using a variable restrictor in conjunction with a volume bottle. If the pneumatic trip valve is connected to the volume bottle, and the restrictor is installed in the supply to the bottle, then a time-delay action for operating a valve is achieved. If the restrictor is installed in the venting line, then a time-delay action for tripping the valve is achieved. A typical variable restrictor with integral check valve is shown in Figure 12. This is sometimes referred to as a “flow control” valve. The check valve allows free flow in one direction and restricted flow in the opposite.

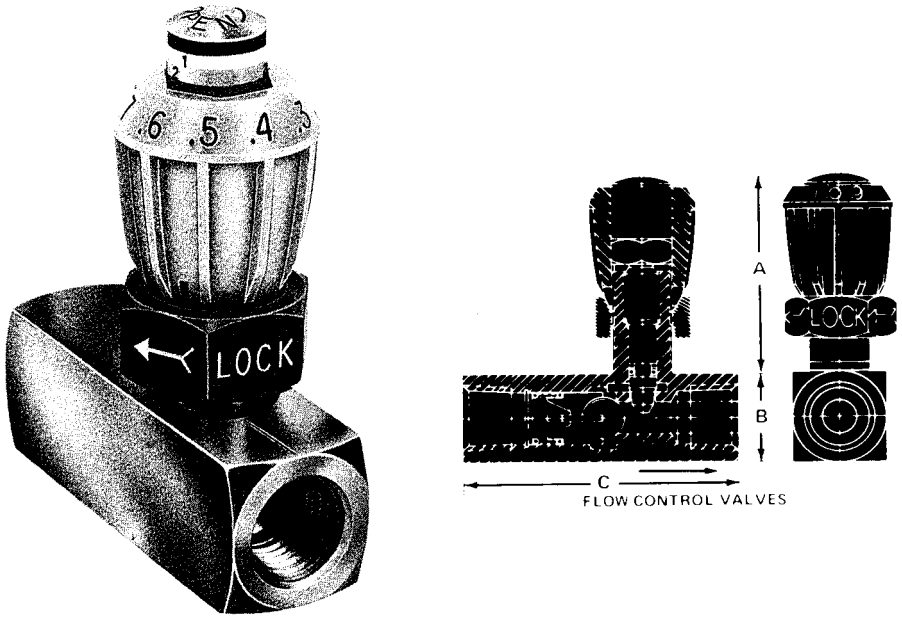

Figure 12: Typical Variable Restrictor with Integral Check Valve (Courtesy of Deltrol and Air-Dreco Inc.)

5. Electrical Systems

5.1. Design

5.1.1.

Many facilities use electrical shutdown systems. The power for the system shall come from a constant source; therefore, most systems use DC voltage. Various voltage levels are used, the most common being 24 VDC. The power is usually supplied from batteries with an AC-powered constant charger system to ensure constant DC voltage with a minimum of AC ripple content; this system is usually called an uninterruptible power supply (UPS). The UPS shall not be used to power other equipment that would put a high drain on the DC power and cause an unwanted shutdown.

5.1.2.

Electrical shutdown systems always shall be designed to “fail safe”, so that on loss of power or signal for any reason, the contacts move to the shutdown or alarm position.

5.1.3.

There are two types of relays used in shutdown system logic design - electromechanical and solid state. Solid state relays are preferred by Mobil.

5.2. Sensing Devices

5.2.1.

Primary sensing devices can measure most process variables. The majority of these sensors use an electromechanical switch actuated by a mechanical linkage.

5.2.2.

The switch contacts are available in a variety of configurations: single pole single throw (SPST), single pole double throw (SPDT), and double pole double throw (DPDT). These terms refer to the contact configuration available in the switch. Shutdown switches are normally specified as DPDT, even if only one set of contacts is to be used in the shutdown system, so that the contacts can be placed in parallel for extra reliability.

5.2.3.

The switch contacts are designated as either normally closed or normally open in the deenergized or shelf position. As it was stated in Section 5.1.2 that loss of power would initiate a shutdown/alarm, sensing devices using an electromechanical switch will open contacts for an unsafe condition, i.e., high pressure or low level. If for any reason, the electric circuit continuity is broken, the result shall be a failsafe action.

5.2.4.

The electrical rating or amperage capacity of the switch shall be suitable for the application. Too low an amperage rating for the application will result in early failure of the electrical contacts. The enclosure material and electrical classification selected shall be suitable for the environment and area classification in which the material is to be installed.

5.3. Relays

5.3.1.

A relay is an electromechanical device which, when energized, magnetically attracts a mechanical arm, which in turn opens and closes electrical contacts.

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Relays are available in a vast array of contact configurations. As stated earlier, solid-state relays are preferred by Mobil.

5.3.2.

Selection shall be based on the specific application. Also, environmental location, available space, complexity of shutdown logic, and power requirements shall be carefully considered.

5.3.3.

Relays are available with built-in time-delay actions of two basic type: ON delay, in which the relay contacts will transfer after the relay is energized for a given time; and OFF delay, in which the relay contacts will transfer after the relay is de-energized for a given time.

5.3.4.

Time-delay relays are used when a predetermined time is required to allow the process to attain its operating level. A typical example is lube oil pressure on a pump or compressor which on start-up is bypassed to allow pressure to build.

5.4. Annunciators

5.4.1.

The indicating lights that appear upon receipt of an alarm or shutdown signal are referred to as the “sequence” of the annunciator. A variety of sequences are available in commercial annunciators, with the first-out sequence being the most common.

5.4.2.

The annunciator shall be powered from a source separate from the shutdown system, with dry contacts employed within the shutdown system for connection to the annunciator. Auxiliary contacts are available on most annunciator relays, but they shall be used only for horn actuation or additional indicators. They shall never be used as part of the shutdown system interlock; otherwise, an annunciator failure would lead to a shutdown.

5.4.3.

The location of alarm or shutdown windows in the annunciator case shall be considered carefully. Related alarms shall be adjacent to each other. Color coding of windows can be employed to differentiate between alarm only,

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shutdown, or emergency shutdowns. A typical annunciator configuration is shown in Figure 13.

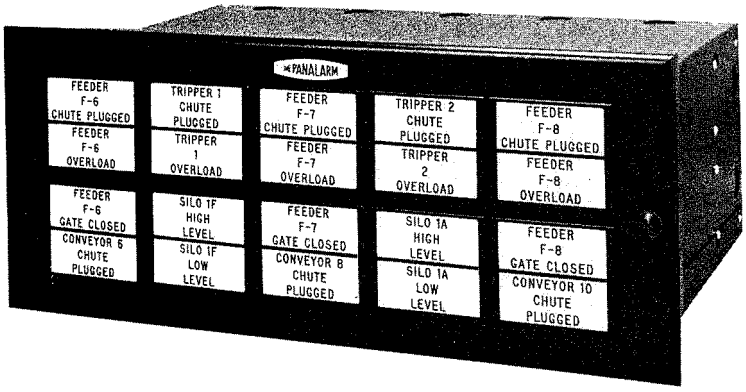

Figure 13: Electrical Annunciators (Courtesy of Ametek, Inc., Panalarm Division, Skokie, IL)

5.5. System Logic

A “ladder diagram” is used to define the logic for either electric or electronic microprocessor systems. Refer to Section 6.2 of the Chilton Process Control Handbook for more details.

5.5.1. Ladder Diagram

The ladder diagram defines each circuit in much the same way as the schematic diagrams described in Section 4 for pneumatic systems.

5.5.2. Bypass Single Devices

Figure 14 shows the same bypass circuit shown as the pneumatic circuit of Figure 3. If the PSH on MBD-2000 must be tested, replaced, or repaired, the bypass switch can be placed in the bypass position, thus keeping relay R1 energized. This also can be done for the PSL and the LSH. Note that to energize SDV-2, relays R1, R2, and R3 shall either be energized by the protective switches or by the bypass switch. (Refer to API RP 14C for nomenclature.)

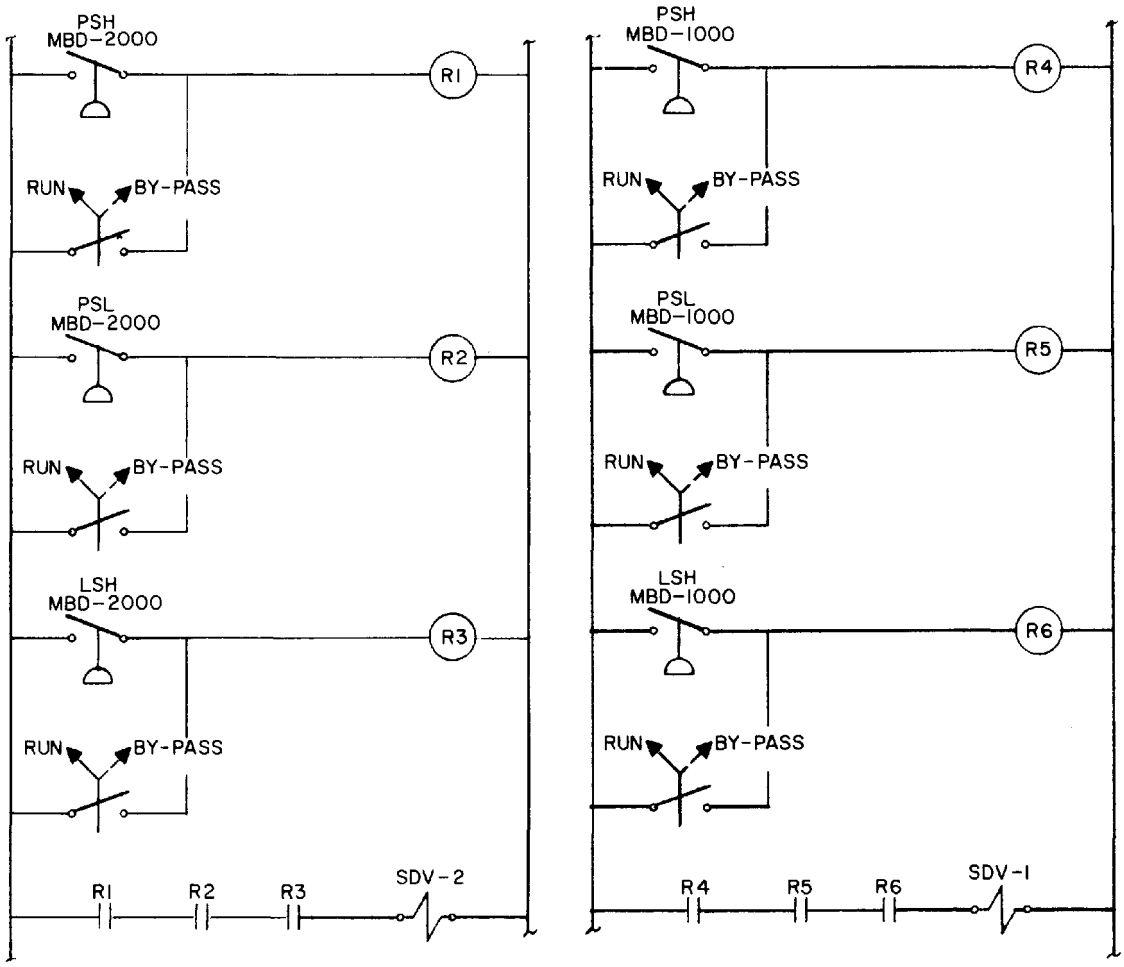

Figure 14: Bypass Circuit

5.5.3. Bypass All Devices

Shutdown logic with total circuit bypass is shown in Figure 15. While the sequence of operation is the same, the bypass switch has been removed from each individual safety device and installed in a way that allows bypassing all three circuits at the same time. This circuit also can be configured with individual bypasses as well as the total circuit bypass.

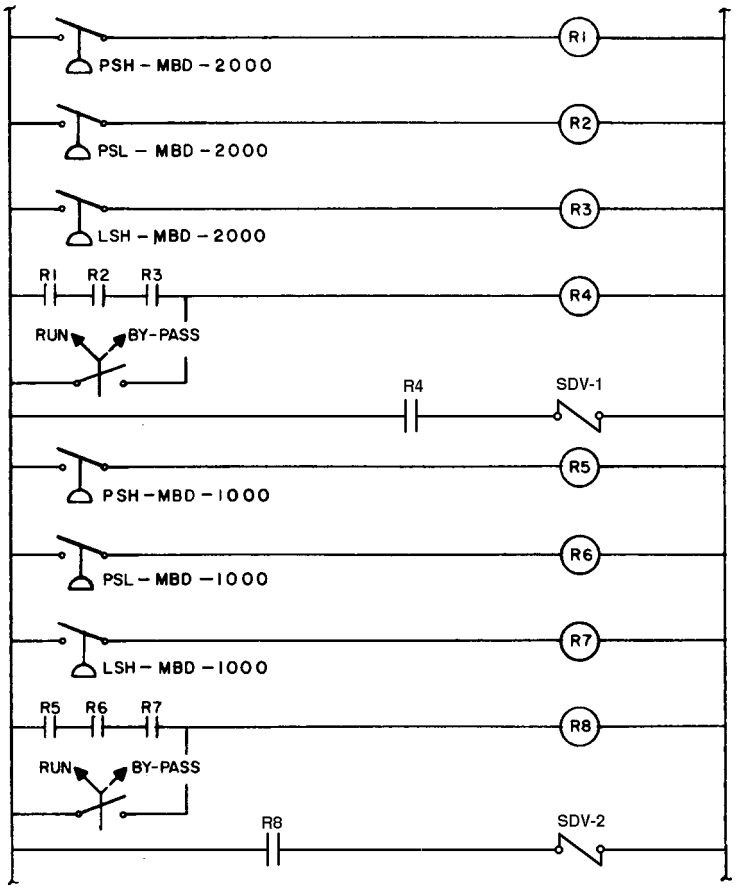

Figure 15: Shutdown Logic with Total Circuit Bypass

5.5.4. Bypass a Train System

Figure 16 illustrates shutdown logic with process train system bypass. The sequence of operation is the same as with the previous two bypasses, except that the bypass switch has to be relocated to bypass all six circuits.

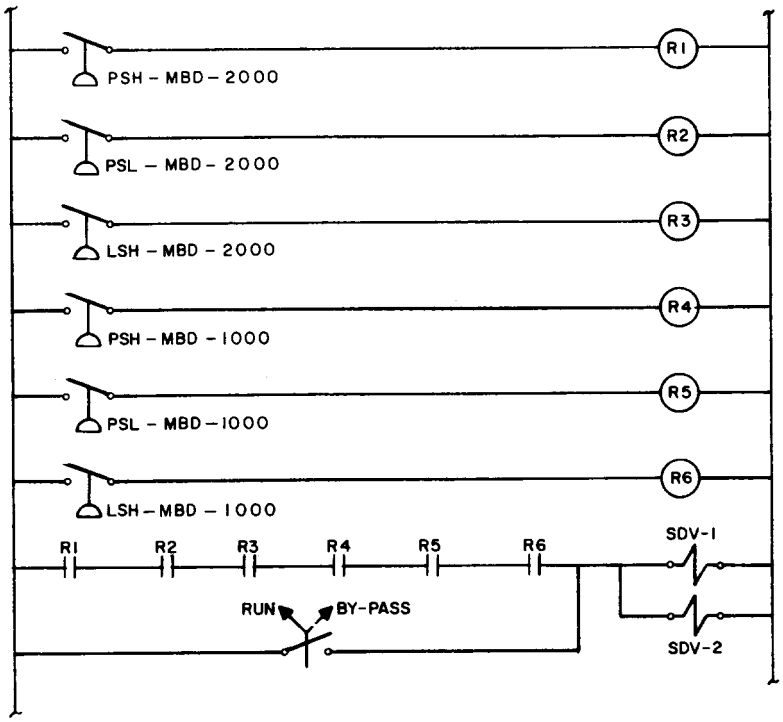

Figure 16: Shutdown Logic with Process Train System Bypass

5.5.5. Lockout and Manual Reset

Shutdown logic with lockout and manual reset are shown in Figures 17 and 18. To understand this circuit, assume that the pressure in vessel MBD-2000 has reached the shutdown point and tripped the PSH, de-energizing relay R1. The contacts on relay R1 will now open, causing SDV-1 to de-energize, thus closing the inlet valve to this vessel. When the inlet is closed, the pressure can return to its normal reading, thus allowing the PSH to reset and energize relay R1. In the previous ladder diagram, the SDV will reopen automatically. R4 self-energizes; once it is tripped, the circuit cannot be energized until the pushbutton to reset R4 is activated. The same feature is shown for R8. (Refer to API RP 14C for nomenclature.)

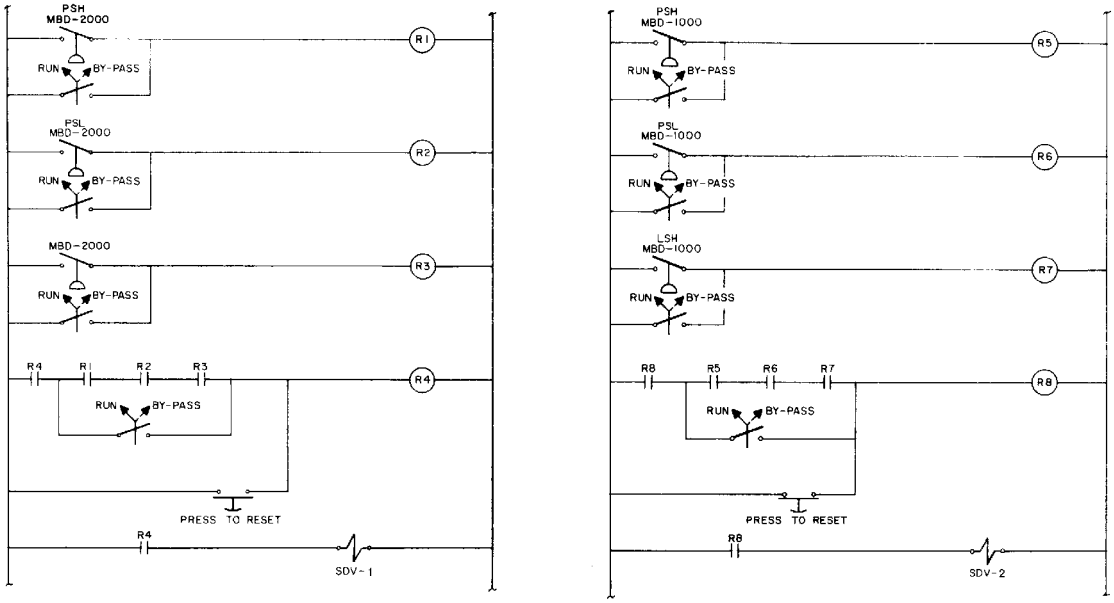

Figure 17: Shutdown Logic

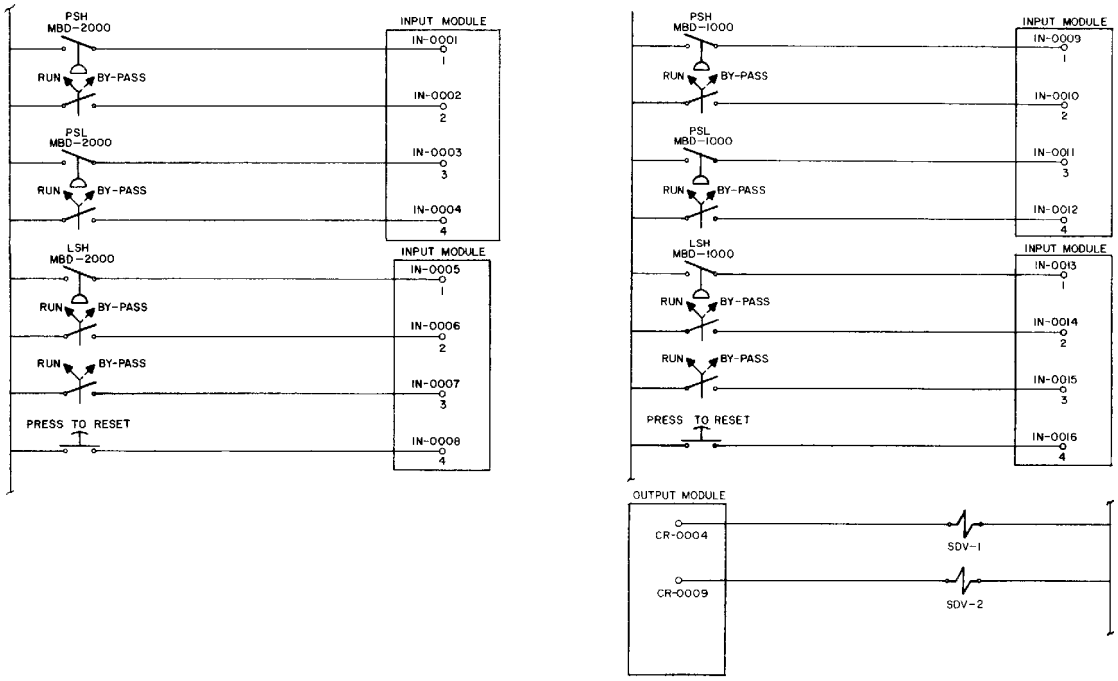

Figure 18A: Shutdown Logic for Typical PLC (Connection Diagram)

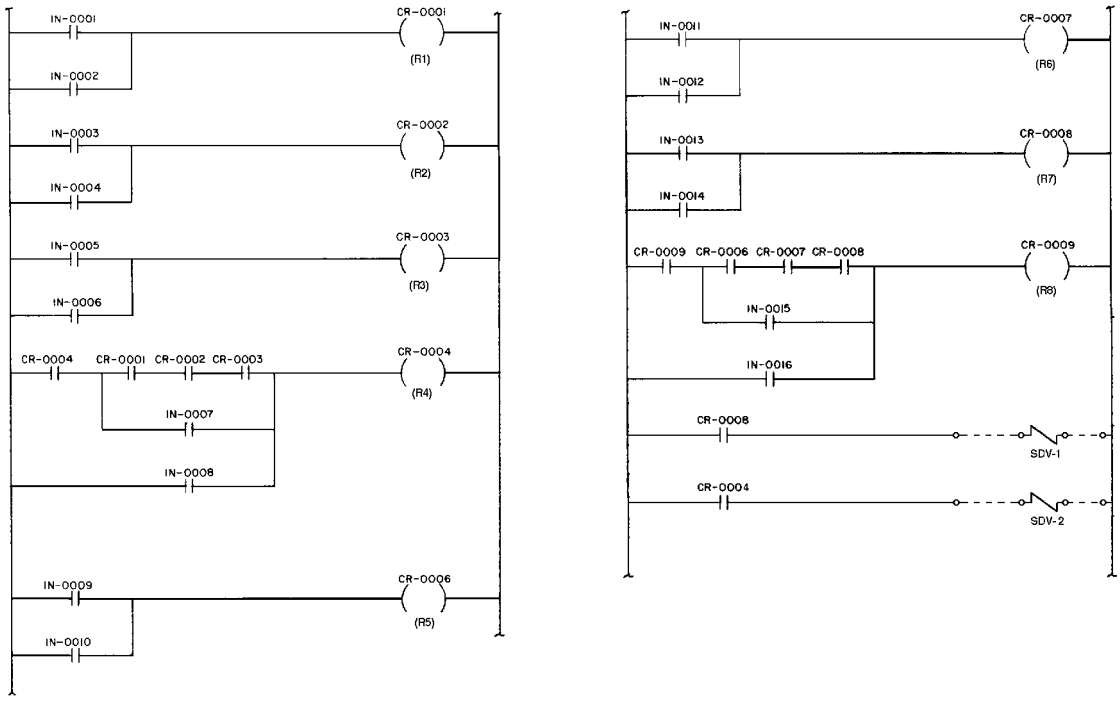

Figure 18B: Shutdown Logic (Operational Diagram)

6. Electronic Systems

6.1.

Microprocessor-based electronic systems have an architecture based on a multiple processor and I/O design. These systems, usually triple redundant, are designed to eliminate common-mode faults and remove all potential latent faults. Usually referred to as fault tolerant safety systems, they normally use three isolated asynchronous processors, each with its own power supply and I/O subsystems. Communications between each CPU is read only. This concept assures complete integrity for data voting and validation. Operation of the system is based on a two out of three voting (of each processor system) sequence to determine safety systems action. A microprocessor-based safety system also incorporates the intelligence to regularly exercise each input and output to ensure that no latent faults are present. The system includes an elaborate diagnostic system to warn the operator of any existing or pending abnormalities.

6.2.

Safety system design is the same as for an electrical system except that the triple redundant microprocessors replace all system relays.

7. Safety Analysis Concepts

7.1. General

7.1.1.

This section discusses potential hazards, conditions that create each hazard, and sources of each condition. By tracing a path to a potential hazard, the designer may develop a system for identifying the process conditions that cause the hazard. Devices can then be installed to monitor and prevent these process conditions. Depending on the severity of the hazard and the ability of other devices to break the chain leading to the hazard, a decision can be made about the number of backup devices required if the primary sensor and shutdown shall fail.

7.1.2.

The function chart in API RP 14C describes the techniques commonly used to ensure that the proper shut-in sensors are specified for each item of equipment, and to provide a format for depicting the function performed by each sensor. Use of this practice is mandated in U.S. federal waters and is appropriate in other areas.

7.1.3.

Although this document discusses design of process safety shutdown systems, it must be emphasized that this is only a small part of facility safety. A mechanically safe flow scheme and physical facility layout are absolute musts as starting points for safety system design. In addition, the facility shall be constructed, maintained, and inspected in accordance with applicable codes and standards and operated by personnel trained and motivated to apply safe operating practices. The best safety system, by itself, cannot assure safety.

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7.2. Hazard Analysis

7.2.1.

A hazard analysis identifies potential hazards, defines the conditions necessary for each hazard, and identifies the source for each condition.

7.2.2.

To construct a hazard tree, one shall first identify potential hazards, then determine the conditions necessary for these hazards to occur, and then determine the source creating these conditions. Using this reasoning, a hierarchy of events, called a hazard tree, can be drawn. In a hazard analysis, starting at the tree's lowest level, an attempt is made to break the chain leading to the hazard by eliminating one of the conditions. Since no condition can be eliminated with absolute certainty, an attempt is made to minimize the occurrence of each step in each chain leading to the hazard, so that the overall probability of the hazard's occurrence is within acceptable limits.

7.2.3.

This process is perhaps best illustrated by a simple example. Figure 19 shows a hazard tree developed for the “hazard” of injury while walking down an office corridor. The conditions leading to injury are identified as collision with others, tripping, being hit by a falling object, and total building failure. The sources leading to each condition are listed beneath it. Some sources can be further resolved into activities that could occur in the source. For example, if no soil boring were taken, this oversight could lead to “inadequate design”, which would lead to “building failure”, and then to “injury”.

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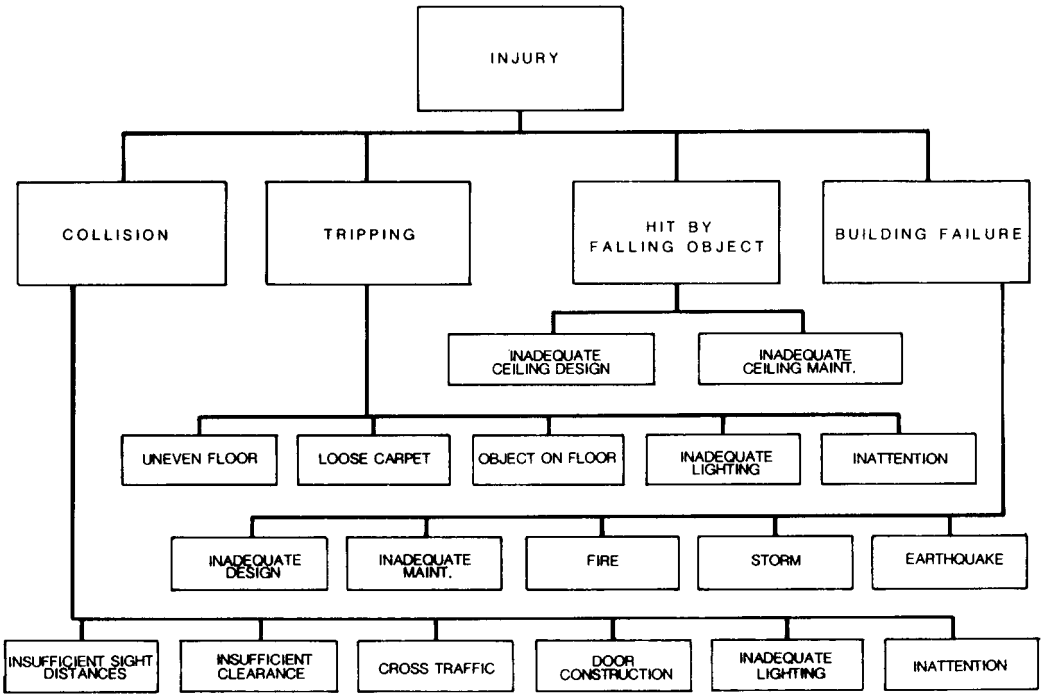

Figure 19: Hazard Tree Developed for Analysis of Walking in an Office Corridor

7.2.4.

It is obviously impossible to be absolutely certain that the hazard tree cannot be broken. However, it is possible to set standards for ceiling design, lighting, door construction, and so on, which will result in acceptable frequencies of hazards, given the severity of the expected injury from the condition. That is, we can conclude that the probability of occurrence of building failure shall be lower than the probability of occurrence of tripping because of the severity of injury associated with building failure.

7.2.5.

It shall be obvious from the preceding discussion that creating a hazard tree is somewhat subjective. Different evaluators will likely classify conditions and sources differently and may carry the analysis to further source levels. However, the conclusions reached concerning building design, maintenance, layout of traffic patterns, lighting, etc., shall be the same. The purpose of developing the hazard tree is to focus attention and help the evaluator identify all aspects that shall be considered in reviewing overall safety levels.

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7.2.6.

It is possible to construct a hazard tree for a generalized production facility, just as for a generalized hallway. That is, Figure 19 is valid for a hallway in Paragon's offices in Houston, in the Post Office Tower in London, or in a residence in Jakarta. Similarly, for a production facility, a generalized hazard tree can be constructed which could be equally valid for an onshore or offshore facility in any geographic location.

7.2.7.

Figure 20 is a hazard tree for a generalized production facility, with the hazards identified as oil pollution, fire/explosion, and injury. Beginning at the top of the tree with injury, we can see that the hazards of fire/explosion and oil pollution become conditions for injury because they can lead to injury. The tree was constructed beginning with the lowest-level hazard, oil pollution. Oil pollution results from an oil spill—but only if there is inadequate containage; if containage is adequate, there cannot be oil pollution. Onshore, dikes are constructed around tank farms for this reason. Offshore, however, and in large onshore facilities, it is not always possible to build containage large enough for every contingency. The requirement for drip pans and sumps stems from the need to reduce the probability of oil pollution that could result from small oil spills.

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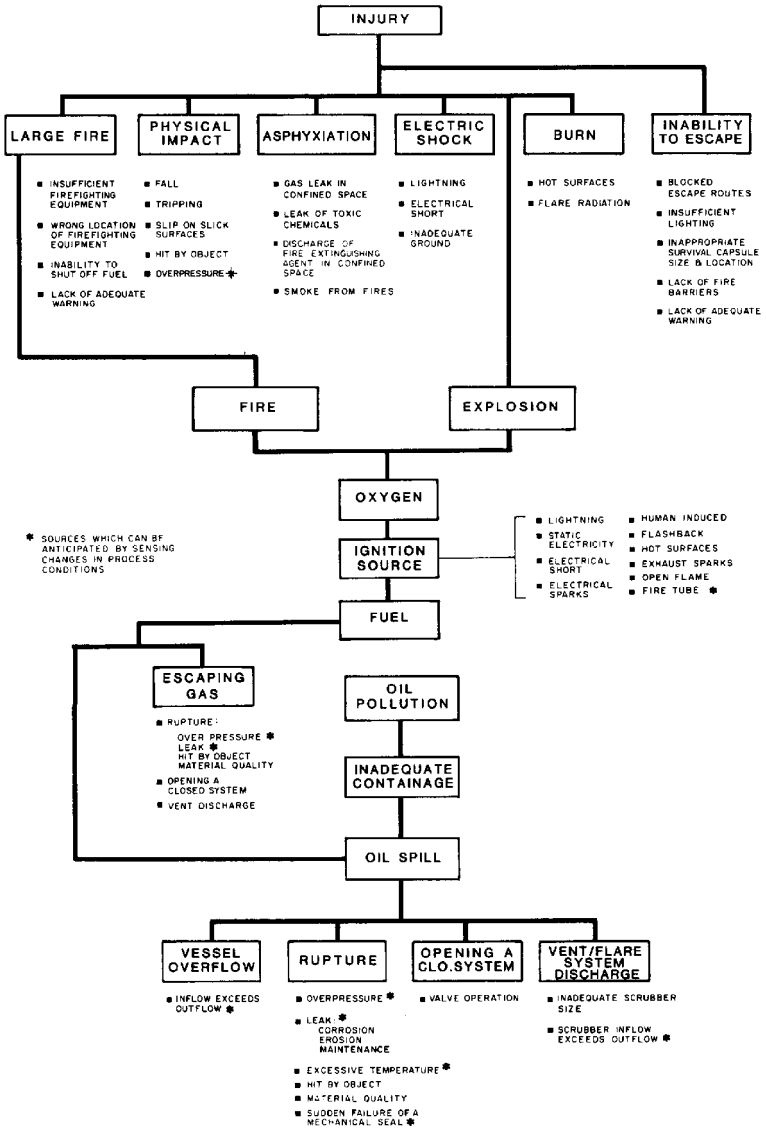

Figure 20: Hazard Tree Developed for a Generalized Production Facility

7.2.8.

One possible source of an oil spill is a vessel overflow. Any vessel with an outlet to the atmosphere can be filled until it overflows. Another source of spills is a rupture or sudden inability of equipment to contain pressure. Of the listed events leading to rupture, some can be anticipated by sensing changes in process conditions, while others cannot.

7.2.9.

Other oil spill sources are listed. For example, if an operator inadvertently forgets to close an open valve, oil may leak from the system, creating a spill. If there is not a dike of adequate size around the system, oil pollution shall result. It is also possible for oil to spill out the vent/flare system. All pressure vessels are connected through a relief valve to a vent or flare system. If the relief scrubber is inadequately sized, or if it lacks a sufficient dump rate, oil shall go out of the vent system.

7.2.10.

Fire and explosion are much more serious events than pollution; they create a catastrophe that can not only lead to pollution, but can also injure people. We clearly want to have more safety levels (that is, a lower probability of occurrence) in the chain leading to fire/explosion than in the chain leading to pollution. Whatever the acceptable risk for oil pollution, a lower risk is necessary for fire/explosion.

7.2.11.

For fire or explosion to occur, fuel, an ignition source, oxygen—and time for them to interact—are needed. If any of these elements can be eliminated with 100 percent assurance, the chain leading to fire/explosion shall be broken. For example, if oxygen can be kept out of the facility, then there can be no fire/explosion. This fire/explosion safeguard can be installed inside the equipment by designing a gas blanket and ensuring positive pressure. For practical purposes it cannot be done outside of the equipment because human interface is necessary.

7.2.12.

Fuel cannot be eliminated with certainty. Oil and gas are present in any production facility, and either an oil spill or escaping gas can provide the fuel needed for explosion. Escaping gas can result from rupture, opening of a closed system (as during purging on start-up), or normal venting procedures. The presence of fuel can be minimized by preventing oil spills and by minimizing the probability of gas escape.

7.2.13.

It is possible to minimize the presence of ignition sources. Lightning and static electricity are common sources of ignition in production facilities; tank vents are often ignited by lightning. Although it is impossible to anticipate this ignition by sensing changes in process conditions, gas blankets, pressure/vacuum valves, and flame arrestors can be installed to ensure that flame will not flash back into the tank and create an explosion. Electrical shorts and sparks are also sources of ignition, but these are kept isolated from fuel by rules and regulations for electrical systems design. In the United

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States, the National Electrical Code and the API recommended practices for electrical systems are employed to minimize the possibility of an electrical short and to keep electrical sparks isolated from fuel. Human-induced ignition sources commonly result from welding and cutting operations; they may also be caused by smoking, hammering (which causes sparks), and so on. Flashback is another source of ignition. In some vessels, a flame exists inside a fire tube. If a fuel source develops around the air intake for the fire tube, the flame can propagate outside the tube and go out into the open. It would then become an ignition source for any nearby fuel and might lead to a fire/explosion. This is why flame arrestors are required on natural-draft fire tubes.

7.2.14.

Hot surfaces are another common ignition source. Engine exhaust, turbine exhaust, and engine manifolds on engine-driven compressors may be sufficiently hot to ignite oil or gas. A hot engine manifold can become an ignition source for an oil leak; engine exhaust can ignite escaping gas. Exhaust sparks from engines and burners can also be a source of ignition, as can any open flame on the facility.

7.2.15.

Fire tubes, especially in heater treaters, where they can be immersed in crude oil, can become ignition sources if the tube develops a leak, allowing crude oil to come in direct contact with the flame. Similarly, if the burner controls fail and the tube overheats, or if the pilot is out and the burner turns on when there is a combustible mixture in the tubes, fire tubes can ignite any nearby fuel.

7.2.16.

Since these ignition sources cannot be anticipated by sensing changes in process conditions, and since oxygen is always present, a hazard analysis shall concentrate on reducing the risk of oil spills and escaping gas occurring when an ignition source is present, or reducing the probability that the ignition source will exist at the same location as an oil spill or gas escape.

7.2.17.

Injury can result from fire, explosion or the other conditions listed in Figure 21. Although a fire can lead directly to injury, normally there are several contributory events before the fire becomes large enough to cause injury. For example, if there were sufficient warning of a developing fire, there would be enough time to escape before injury could result. If the fuel could be shut off and there were sufficient firefighting equipment to contain the fire before it became large, again the probability of injury would be less.

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7.2.18.

When an explosion occurs, however, it can lead directly to injury. A substantial cloud of gas can accumulate before the combustible limit reaches an ignition source, and the force of the explosion as the cloud ignites can be powerful.

7.2.19.

There are other probable causes of injury: physical impact due to falling, tripping, or slipping on a slick surface; being hit by an object; direct physical impact from a rupture; or asphyxiation, especially when dealing with toxic chemicals. Electric shock and burns can also lead to injury. Burns can result from touching hot surfaces or from radiation.

7.2.20.

The probability of injury from any of these conditions is increased by inability to escape; the longer people are exposed to the situation, the more likely they will be injured. Therefore, escape routes, lighting, appropriate selection of survival capsules or boats, fire barriers, and so on, all lead to a reduction in injuries.

7.3. Developing a Safe Process

7.3.1.

In examining this hazard tree, it is apparent that many sources and conditions leading to the three major hazards have nothing to do with process design. Many sources of hazards cannot be anticipated by sensing a condition in the process. For example, there is no sensor that can be put on a separator to prevent a maintenance worker approaching the separator from falling. Another way of stating this is that many of the sources and conditions identified on the hazard tree require design considerations that do not appear on mechanical flow diagrams. The need for proper design of walkways, escape paths, electrical systems, firefighting systems, insulation on piping, etc., are all clearly indicated on the hazard tree. In developing a process safety system, only those items starred (*) in the hazard tree can be considered.

7.3.2.

The limits of design in safety system effectiveness must be emphasized because these limits mean that a production facility designed with a process shut-in system as described in API RP 14C is not necessarily “safe”. Such a system has an appropriate level of devices and redundancy to reduce the risk from the sources and conditions that can be anticipated by sensing changes in process conditions. However, much more is required in facility design if the

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overall probability of any one chain leading to a hazard is to be acceptable. That is, API RP 14C is merely a document about safety analysis of the process components in the production facility. It does not address all the other concerns necessary for a "safe" design.

7.3.3.

The starred items in the hazard tree that can be sensed as changes in process conditions that could develop into sources and lead to hazards are identified in Table 1 in the order of their severity.

Table 1: Sources Associated with Process System Changes

Source	Hazard	Contributing Source or Condition
Overpressure	Injury	None
	Fire/explosion	Ignition source
	Pollution	Inadequate containage
Leak	Fire/explosion	Ignition source
	Oil pollution	Inadequate containage
Fire Tubes	Fire/explosion	Fuel
Excessive temperature	Fire/explosion	Ignition source
	Oil pollution	Inadequate containage
Inflow exceeding outflow	Oil pollution	Inadequate containage

7.3.4.

Overpressure can lead directly to all three hazards: to injury; to fire or explosion if there is an ignition source; or to pollution if there is inadequate containage. Therefore, there shall be a high level of assurance that overpressure will occur very infrequently.

7.3.5.

Fire tubes can lead to fire/explosion if there is a crude oil leak into the tubes or burner control failure. The resulting explosion could be sudden and cause immediate injury; therefore, a high level of safety is required.

7.3.6.

Excessive temperature can lead to premature equipment failure at pressures below the equipment's design maximum working pressure, creating a leak potentially leading to fire/explosion if gas is leaked, or oil pollution if oil is leaked. This type of failure shall be gradual, with warning as it develops, and thus does not require the same degree of protection as those just mentioned.

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7.3.7.

Leaks cannot lead directly to personal injury; however, they can lead to fire/explosion if there is an ignition source, and to oil pollution if there is inadequate containage. Both the immediacy of the developing hazard and its magnitude will be smaller with leaks than with overpressure. Thus, although it is necessary to protect against leaks, this protection shall not require the same safety level required to protect against overpressure.

7.3.8.

Inflow exceeding outflow can lead to oil pollution if there is inadequate containage; it can also lead to fire/explosion and possible injury by creating an oil spill. This situation is more time-dependent and lower in damage magnitude; therefore, an even lower level of safety shall be acceptable.

7.3.9.

The hazard tree also helps identify protection devices for inclusion in equipment design, potentially minimizing the possibility that a source will develop into a condition. Some examples of such devices are flame arrestors and stack arrestors on fire tubes to prevent flashback and exhaust sparks; gas detectors to sense the presence of a fuel in a confined space; and fire detectors and manual shutdown stations to provide adequate warning and keep a small fire from developing into a large one.

7.4. Primary Defense

Before discussing the safety devices required for the process, it is important to note that the primary safety defense in a process system is careful planning to ensure that the system is made of proper material of sufficient strength and thickness to withstand normal operating pressures. This assurance results from designing the equipment and piping in accordance with accepted industry codes; if this is not done, no sensors will be sufficient to protect against overpressure, leaks, or other hazards. For example, a pressure vessel specified for 10,200 kPa (1480 psi) maximum working pressure will have a relief valve set at 10,200 kPa (1480 psi), but if the vessel is not properly designed and inspected, it may rupture before reaching 10,200 kPa (1480 psi). The best defense against such an occurrence is to use the proper codes and design procedures and to ensure adequate inspection of the manufacture of the equipment and its fabrication into systems. In the United States, pressure vessels are constructed in accordance with the ASME Boiler and Pressure Vessel Code, and piping systems are constructed in accordance with one of the ANSI piping codes.

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7.5. Failure Mode Effect Analysis–FMEA

7.5.1.

One procedure used to determine which sensors are needed to sense process conditions and protect the process is called Failure Mode Effect Analysis (FMEA). Every device in the process is checked for its various modes of failure. Then a search is made to ensure a redundancy that keeps an identified source or condition from developing for each potential failure mode. The degree of required redundancy depends on the severity of the source. Table 2 lists failure modes for various devices commonly used in production facilities.

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Table 2: Failure Modes of Various Devices

1.	Sensors	
	FTS	Fail to Sense
	OP	Operate Prematurely
2.	Check Valves	
	FTC	Fail to Close (Check)
	LIN	Leak Internally
	LEX	Leak Externally
3.	Orifice Plate (Flow Restrictor)	
	FTR	Fail to Restrict
	BL	Block
4.	Pumps	
	FTP	Fail to Pump
	POP	Pump to Overpressurization
	LEX	Leak Externally
5.	Controllers	
	FTCL	Fail to Control Level
	FTCT	Fail to Control Temperature
	FTCF	Fail to Control Flow
	OP	Operate Prematurely
	FTCLL	Fail to Control Low Level
	FTCHL	Fail to Control High Level
	FTRP	Fail to Reduce Pressure
	FTCP	Fail to Control Pressure
	FTAA	Fail to Activate Alarms

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Table 2 (Continued)

6.	Valves	
	FO	Fail Open
	FC	Fail Close
	FTO	Fail to Open
	FTC	Fail to Close
	LIN	Leak Internally
	LEX	Leak Externally
7.	Signal-Indicator	
	FTI	Fail to Indicate
8.	Switch	
	FS	Fail to Switch
	FC	Fail Close
	FO	Fail Open
9.	Engine	
	FTD	Fail to Deliver
	FXP	Deliver Excess Power
10.	Transformer	
	FTP	Fail to Function
11.	General	
	OF	Overflow
	NP	Not Processed
	NS	No Signal
	FP	Fail to Power
	MOR	Manual Override
	NA	Not Applicable
12.	Rupture Disc	
	RP	Rupture Prematurely
	FTO	Fail to Open
	LEX	Leak Externally

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Table 2 (Continued)

Failure Modes of Various Devices		
13.	Meter	
	FTOP	Fail to Operate Properly
	LEX	Leak Externally
	BL	Block
14.	Timer	
	FTAP	Fail to Activate Pump
	FTSP	Fail to Stop Pump

7.5.2.

Before FMEA is applied, a mechanical flow diagram shall be developed. As an example, consider the check valve on a liquid dump line. It can fail in one of three ways: it can fail to close, it can leak internally, or it can leak externally. The FMEA investigates the possible effects shall this particular valve fail to close. Assuming the valve may fail, the system shall include some redundancy that keeps a source from developing. Next, the process would evaluate the second failure mode; that is, what occurs if the check valve leaks internally. Then the process would be examined for the third possible failure. (Check valves are easy: a controller has nine failure modes and a valve has six.)

7.5.3.

To perform a complete, formal FMEA of a production facility, each failure mode of each device shall be evaluated. A percentage failure rate and failure cost for each mode of each device shall be calculated. If the risk-discounted cost of failure is acceptable, then there are the proper numbers of redundancies. If that cost is unacceptable, then other redundancies shall be added until an acceptable cost is attained.

7.5.4.

Obviously, such an approach is very lengthy, requiring many pages of difficult-to-check documentation. Also, such an approach is subjective in that the evaluator must make decisions about the consequence of each failure, the expected failure rate, and the acceptable level of risk for the supposed failure.

7.5.5.

This procedure has been performed on several offshore production facilities with inconsistent results. That is, items identified by one set of evaluators as

required for protection in one design were not required by another set of evaluators in a nearly identical design. In addition, potential failure of some safety devices in one facility caused evaluators to require additional back-up safety devices, but when evaluating a similar installation that had no initial safety devices at all, the same group neither identified the absence of the primary safety devices as a hazard nor required back-up safety devices.

7.5.6.

It shall be clear that a complete FMEA approach is impractical for the evaluation of production facility safety systems for the following reasons:

1. The cost of failure is not as great as for nuclear power plants or rockets, where this technology has proved useful.
2. Production facility design projects cannot support the engineering cost and lead time associated with such an analysis.
3. Regulatory bodies are not sufficiently staffed to critically analyze the output of an FMEA for errors in subjective judgment.
4. Most importantly, there are similarities in all production facility designs that have allowed industry to develop a modified FMEA approach that can satisfy all these objections.

7.6. Modified FMEA Approach

7.6.1.

The modified FMEA approach evaluates each piece of equipment (not each device) as an independent unit, assuming worst-case conditions of input and output. For example, separators, flowlines, heaters, and compressors function in the same manner no matter the specific design of the facility. That is, they have level, pressure and temperature controls and valves subject to failure modes that affect the equipment in the same manner. Thus, an FMEA analysis performed on a piece of equipment standing alone will be valid for that component in any process configuration.

7.6.2.

Furthermore, once every process component has been analyzed separately for worst-case, stand-alone conditions, no additional safety risk is created by joining the components into a system. That is, if every process component is fully protected based on its FMEA analysis, a system made up of several of these components shall also be fully protected.

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7.6.3.

It is even possible that protection furnished by devices on one process component can protect others in the system configuration. That is, devices necessary to provide adequate protection for a component standing alone may be redundant once all components are assembled in a system. This modified FMEA procedure is outlined below:

1. For each piece of equipment (process component), develop an FMEA by assuming in turn that each process upset that can be sensed occurs. That is, assume a control failure, leak, or other event leading to a process upset.

2. Provide a sensor that detects the upset and shuts in the process before an identified source or condition develops. For example, if the pressure controller fails and the pressure increases, provide a high-pressure sensor to shut in the process. If there is a leak and the pressure decreases, provide a low-pressure sensor to shut in the process.

3. Apply FMEA techniques to provide an independent backup to the sensor as a second level of defense against creation of an identified hazard. The degree of reliability of the backup device depends on the severity of the problem. For example, since overpressure can lead to severe hazards, the necessary backup device shall be extremely reliable. Typically, a high-pressure sensor would be backed up by a relief valve, which, in this case, is actually more reliable than the high-pressure sensor, but has certain detriments. Oil leakage, on the other hand, is not as severe, so a drip pan to protect against oil pollution may be adequate backup.

4. Assume that two levels of protection are adequate. Experience in applying FMEA analysis to production equipment indicates that often only one level of protection would be required, given the degree of reliability of shutdown systems and the consequences of failure. In engineering time, it is more costly to document that only one level is required for a specific installation than it is to install and maintain two levels; therefore, two levels are usually specified.

5. Assemble the components into the process system and apply FMEA techniques to determine if protection devices on some components provide redundant protection to other components. For example, if there are two separators in series, one cannot be bypassed while the other is in service, and if they are both designed for the same pressure, the devices protecting one from overpressure also shall protect the other, possibly eliminating any need for two sets of high-pressure sensors.

7.6.4.

The application of this procedure is best seen by performing an FMEA on a simple two-phase separator. Table 3 lists the process upsets that can be sensed before an undesirable event leading to a source or condition occurs. For overpressure, primary protection is provided by a high-pressure sensor

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that shuts in the inlet (PSH). If this device fails, secondary protection is provided by a relief valve (PSV).

Table 3: FMEA of a Separator

Undesirable Event	Primary Protection	Secondary Protection
Overpressure	PSH	PSV
Large Gas Leak	PSL and FSV	ASH, Minimize Ignition Sources
Large Oil Leak	LSL and FSV	Sump Tank (LSH)
Small Gas Leak	ASH, Minimize Ignition Source	Fire Detection
Small Oil Leak	Sump Tank (LSH)	Manual Observation
Inflow Exceeds Outflow	LSH	PSH and Downstream Vessel (LSH)
High Temperature	TSH	Leak Detection Devices

7.6.5.

A large gas leak is detected by a low pressure sensor (PSL) and a check valve (FSV) to shut in the outlet and prevent gas from downstream components from flowing backward to the leak. Similarly, a large oil leak is detected by a low level sensor (LSL) and a check valve. Backup protection against a large oil leak is furnished by a sump tank and its high level sensor (LSH), which is a second defense against an oil spill becoming pollution. Backup protection for a large gas leak is provided by minimizing ignition sources and providing gas detectors where gas could accumulate.

7.6.6.

It shall be clear that small leaks; i.e., where the leak rate is less than the inlet rate, will not be detected by this method. Secondary protection becomes primary for small leaks since the consequence of such a leak is less severe. Backup protection against a small gas leak then becomes fire detection and protection equipment if the small leak were to cause a fire. Other than manual observation, there is no backup for a small oil leak before containage is exceeded and oil pollution results.

7.6.7.

The primary guard against high temperature, which could lower the maximum allowable working pressure below the PSV setting, is a high-temperature sensor (TSH) that shuts in the inlet or the source of heat. Backup protection is provided by leak detection devices.

7.6.8.

Inflow exceeding outflow is sensed by a high-level sensor (LSH). Backup protection is furnished by the PSH (to keep the relief valve from operating), or an LSH in a downstream vent scrubber if the vessel gas outlet goes to

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atmosphere. That is, a vent scrubber shall be installed downstream of any vessel that discharges directly to atmosphere.

7.6.9.

Once the FMEA is completed, the specific system is analyzed to determine if all the devices are actually needed. For example, if it is impossible for the process to overpressure the vessel, these devices are not required. If it is impossible to heat the vessel to a high enough level to affect its maximum working pressure, the TSH can be eliminated.

7.7. API Recommended Practice

7.7.1.

The API has used the modified FMEA approach to develop its API RP 14C. Although this document was developed for offshore facilities, it can be applied to those onshore facilities where the risk of failure is sufficiently high. In this document, 10 different process components have been analyzed, and a Safety Analysis Table (SAT) has been developed for each component. A sample SAT for a pressure vessel is shown in Table 4. The fact that Tables 3 and 4 are not identical is due both to the subjective nature of a hazard analysis and FMEA, and to the fact that API RP 14C is a consensus standard. Nevertheless, although the rationale differs somewhat, the devices required are identical. (The "gas make-up system" in Table 4 is not really required by API RP 14C, as we shall see.)

Table 4: Safety Analysis Table (SAT)–Pressure Vessels

Undesirable Event	Cause	Detectable Condition Component	Protection	
			Primary	Secondary
Overpressure	Inflow exceeds outflow	High pressure	PSH	PSV
	Thermal expansion			
	Blocked outlet			
Underpressure	Withdrawals exceed inflow	Low pressure	Gas make-up system	PSL
	Thermal contraction			
Overflow	Liquid inflow exceeds liquid output capacity	High liquid level	LSH	*LSH and *PSH
	Level control failure			
Gas Blowby	Level control failure	Low liquid	LSL	*PSH and *PSV or *Vents
Leak	Deterioration	Low pressure and backflow	PSL and FSV	ESS
	Rupture			

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	Accident			
Excess temperature (process)	Excess heat input	High temperature	TSH	Safety devices on heat source
*At downstream component				

7.7.2.

API RP 14C also provides standard reasons for allowing elimination of certain devices when the process component is considered as part of an overall system. Each safety device identified by the SAT (except the “gas make-up system”) is listed in a Safety Analysis Checklist (SAC) table such as Table 5. The device shall either be installed or eliminated if one of the reasons listed is valid.

Table 5: Safety Analysis Checklist (SAC)–Pressure Vessels (From API RP 14C)

A. High Pressure Sensor (PSH)

1. PSH installed
2. Input is from a pump or compressor that cannot develop pressure greater than the maximum allowable working pressure of the vessel.
3. Input source is not a wellhead flowline(s), production header or pipeline, and each input source is protected by a PSH that protects the vessel.
4. Gas outlet is connected by adequately sized piping without block or regulating valves to downstream equipment protected by a PSH which also protects the upstream vessel.
5. Vessel is final scrubber in a flare, relief, or vent system and is designed to withstand maximum built-up back pressure.
6. Vessel operates at atmospheric pressure and has an adequate vent system.

B. Low Pressure Sensor (PSL)

1. PSL installed.
2. Minimum operating pressure is atmospheric pressure when in service.
3. Each input source is protected by a PSL and there are no pressure control devices or restrictions between the PSL(s) and the vessel.
4. Vessel is scrubber or small trap, is not a process component and adequate protection is provided by downstream PSL or design function (e.g., vessel is gas scrubber for pneumatic safety system or final scrubber for flare, relief, or vent system).
5. Gas outlet is connected by adequately sized piping, without block or regulating valves, to downstream equipment protected by a PSL which also protects the upstream vessel.

C. Pressure Safety Valve (PSV)

1. PSV installed.
2. Each input source is protected by a PSV set no higher than the maximum allowable working pressure of the vessel and a PSV is installed on the vessel for fire exposure and thermal expansion.
3. Each input source is protected by a PSV, set no higher than the maximum allowable working pressure of the vessel, of which at least one PSV cannot be isolated from the vessel.
4. PSVs on downstream equipment can satisfy relief requirement of the vessel and cannot be isolated from the vessel.

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Table 5 (Continued)

D.	High Level Sensor (LSH)	
	1.	LSH installed.
	2.	Equipment downstream of gas outlet is not a flare or vent system and can safely handle maximum liquid carryover.
	3.	Vessel function does not require handling separated fluid phases.
	4.	Vessel is small trap from which liquids are manually drained.
E.	Low Level Sensor (LSL)	
	1.	LSL installed to protect each liquid outlet.
	2.	Liquid level is not automatically maintained in the vessel, and the vessel does not have an immersed heating element subject to excess temperature.
	3.	Equipment downstream of liquid outlet(s) can safely handle maximum gas rates that can be discharged through the liquid outlet(s), and vessel does not have an immersed heating element subject to excess temperature. Restrictions in the discharge line(s) may be used to limit the gas flow rate.
F.	Check Valve (FSV)	
	1.	FSV installed on each outlet.
	2.	The maximum volume of hydrocarbons that could backflow from downstream equipment is insignificant.
	3.	A control device in the line will effectively minimize backlflow.
G.	High Temperature Sensor (TSH)	
	1.	TSH installed.
	2.	(Deleted in Second Edition.)
	3.	Heat source is incapable of causing excess temperature.

7.7.3.

The installation of devices is documented in a Safety Analysis Function Evaluation (SAFE) chart. Refer to API RP 14C for a typical SAFE chart which shows how the SAFE chart is cross referenced to the SAC table. For more information on SAFE charts, see the tutorial EPT 05-T-01 on Instrumentation Basics.

7.8. Hazards Analysis

The above procedure discusses procedures for designing safety shutdown systems. API RP 14J describes techniques and presents an example checklist for performing hazards analysis of production facilities. This checklist addresses those aspects of safety, identified from the hazard tree (Figure 21), that require further mitigation than can be handled by the safety shutdown system alone. In other words, the checklist defines areas requiring further action.

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Scope

This Mobil Engineering Practice (MEP) presents the requirements for the design, installation and testing of Triple Modular Redundant–Programmable Electronic Systems (TMR–PES) for use in Safety Instrumented Systems (SIS) for onshore and offshore petroleum production facilities, petroleum refineries, petrochemical plants and other industrial applications.

Version 0

Table of Contents

Scope **1**

1. References **4**

1.1. MEPS–Mobil Engineering Practices 4

1.2. IEC–International Electrotechnical Commission 4

1.3. IEEE–Institute of Electrical and Electronic Engineers 4

1.4. NFPA–National Fire Protection Association 4

1.5. Military Handbook 4

2. General **5**

2.1. General Requirements 5

2.2. Scope of System 6

3. Design **6**

3.1. Construction 6

3.2. Environment 7

3.3. Operating Architecture 7

3.4. CPU Operating Modes 10

3.5. Status Indication 10

3.6. Fault Tolerance and Self-Checking 11

3.7. I/O Modules 11

3.8. External Communication 13

3.9. Enclosures 14

3.10. Power Supply 15

4. I/O Requirements **16**

4.1. General 16

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4.2. I/O List 17

5. Wiring and Terminations 17

5.1. Wiring 17

5.2. Terminal Blocks 18

5.3. Cabling 18

5.4. Nameplates and Tagging 18

6. Hardwired Inputs And Outputs 20

7. Engineering and Operator Console and Printers 20

8. Programming and Software Configuration 21

8.1. Application Software 21

8.2. Man-Machine Interface (MMI) Software 23

8.3. Bypass Switches 23

9. Inspection and Testing 23

9.1. Pre-Acceptance Tests 23

9.2. Acceptance Tests 24

9.3. Factory Acceptance Test (FAT) 24

9.4. Site Acceptance Test (SAT) 25

9.5. Sustained Performance Test (SPT) 26

9.6. Inspections 26

10. Documentation 27

10.1. General 27

10.2. Vendor's Services 28

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1. References

The following publications form a part of this Practice. Unless otherwise specified herein, use the latest edition.

1.1. MEPS–Mobil Engineering Practices

MP 32-P-21	Wiring for Instrumentation and Digital Systems

1.2. IEC–International Electrotechnical Commission

IEC 61131-3	Programmable Controllers - Part 3: Programming Languages

1.3. IEEE–Institute of Electrical and Electronic Engineers

IEEE C37.90.1	Standard Surge Withstand Capability (SWC) Tests for Protective Relays and Relay Systems R(1994)
IEEE 730	Standard for Software Quality Assurance Plans Revision of IEEE Std 730-84 and Redesignation of IEEE 730.1-89; IEEE Computer Society Document
IEEE 828	Standard for Software Configuration Management Plans
IEEE 1042	Guide to Software Configuration Management IEEE Computer Society Document R(1994)

1.4. NFPA–National Fire Protection Association

NFPA 70	National Electrical Code 1996 Edition Errata #1; Tentative Interim Amendment 1996

1.5. Military Handbook

MIL HDBK-217F	Reliability Prediction of Electronic Equipment

2. General

The design, installation and testing of Triple Modular Redundant–Programmable Electronic Systems (TMR–PES) for use in Safety Instrumented Systems (SIS), for onshore and offshore petroleum production facilities, petroleum refineries, petrochemical plants and other industrial applications, shall be in accordance with requirements of this MEP, unless superceded by more stringent local regulations.

2.1. General Requirements

2.1.1. System Configuration

The system shall be composed of vendor's standard hardware, system software and firmware. Vendor's standard operating system software shall not be modified to meet any of the requirements, including all executive and diagnostic software. Ladder logic and application software shall be implemented in a manner that requires no modification to the system operating software. In no case shall a PES be used if it is based on a custom programmed microprocessor (i.e., one-of-a-kind system).

2.1.2. Vendor Support

All hardware, software and firmware supplied with the system shall have been field proved prior to placement of the order. Field proved is defined as successful operation at a field installation for six or more months. Vendor shall support all system hardware and firmware with spare parts and service for a period of 15 years from placement of order or 10 years from the end of warranty, whichever period ends last.

2.1.3. Vendor References

The TMR-PES vendor shall provide trained and experienced personnel for product application support. The TMR-PES shall have a proven record of reliable operation. At Mobil's request, the TMR-PES vendor shall provide a list of installations, customers and contacts.

2.1.4. Reliability

The TMR-PES shall have a high degree of availability and reliability. The TMR-PES manufacturer shall provide an availability and reliability analysis and the TMR-PES calculations used, based on MIL HDBK-217F. The analysis shall be by a certified third party such as Factory Mutual

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Engineering, Canadian Standards Association, British Standards Institute, etc.

2.2. Scope of System

- The TMR-PES shall use three processors with two out of three processors voting to establish high data integrity and error-free, uninterrupted process operation.
- The TMR-PES system Input/Output (I/O) cabinets may integrate with the main processors and/or work separately. Whatever the configuration, the system shall be considered as one operating unit for tests, inspection and operation.
- The TMR-PES shall be furnished with Sequence of Events (SOE) recording software.
- The TMR-PES design shall be capable of future I/O expansion, which shall be achieved by addition of equipment, without modifying or replacing existing equipment, communications cables or system operating software.
- I/O assignment, ladder logic configuration and sequence programming shall be generated from the Safety Analysis Function Evaluation (SAFE) Chart Diagrams, graphic designs and SOE report format and contents.
- Programming systems shall be compliant with IEC 61131-3 and permit direct downloading from the electronic engineering drawings into the PES without translation from Functional Block Diagram (FBD) format to Ladder Code (LD) format. See Section 8 of this MEP for additional requirements.

3. Design

3.1. Construction

- The TMR-PES shall be a microprocessor-based system designed to perform discrete and analog control in an industrial environment.
- The TMR-PES shall be of modular construction, allowing input and output (I/O) racks and modules to be individually added or removed without disturbing other racks or modules.
- TMR-PES modules (CPU, power supply, I/Os, etc.) shall be designed to provide for free airflow (convection) cooling.
- Online removal/replacement of any TMR-PES module shall be possible without having to reconfigure system software, alter system wiring or cabling, de-energize system or module power, re-initialize the TMR-PES or compromise TMR-PES safety functions.

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- In general, dedicated I/O chassis shall be assigned for non-process (i.e., Fire and Gas I/Os) and process shutdown (PSD) I/Os. Mixing of non-process and process I/Os are allowed in the same chassis where the I/Os are equipment- or location-related.

3.2. Environment

- As a minimum, the TMR-PES shall be capable of operating from 32°F–122°F and from 5–95 percent relative humidity without condensation.
- The TMR-PES shall be capable of operating in a high electrical-noise environment, with appropriate EMI/RFI shielding.

3.3. Operating Architecture

The TMR-PES architecture shall employ three separate processors with triplicated I/O and bus structure. Sensor signals shall be separated into three isolated paths, compared and voted in a two-out-of-three arrangement. The signals are then sent via three separate paths to each processors, where two-out-of-three voting is again performed on the data. Each processor shall execute its individual application program simultaneously and independently verifying data, executing logic instructions and controlling calculations, clock and voter/synchronization signals.

- Main processors and communications modules shall be triplicated with a two-out-of-three arrangement.
- The CPU shall contain the program memory, either in nonvolatile EPROM or battery backed RAM, with a minimum of six month battery backup of all memory contents.
- The SIS design requirements shall use no more then 50 percent of the CPU's processing and memory capability.
- Hot replacement of a CPU shall not require any process interruption or system reinitialization.

3.3.1. Program Functions

The CPU shall include, but not be limited to, the following program functions:

- Contacts
- Coils
- Latching coils
- Timers (on-delay, off-delay)
- Counters (up, down and high speed)
- Master control relays

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- Zone control relays
- Sequencer
- Bit-shift registers
- I/O force functions

3.3.2. Math Functions

The CPU shall also be capable of the following math functions:

- Add
- Subtract
- Multiply
- Divide
- Square root
- Move
- Shift
- First-in, first-out compare
- Logical AND
- Logical OR functions
- Conversion of BCD to binary and binary to BCD
- Floating-point calculations, including integer to floating point conversion and floating point to integer conversion

3.3.3. Clock

The CPU shall include a real-time clock that can be accessed by the ladder logic, another user program or report generation software. The clock shall include functions for year, month, day, hour, minute, second and millisecond.

3.3.4. Networking/Communication Capabilities

The CPU's of the same manufacturer/series shall have networking capabilities with each other.

3.3.4.1. Peer-to-Peer Communications

The network shall support "peer-to-peer" communications, so that all data from one CPU station moves between any two or more CPU stations on the network without the necessity of a "master" and "slave" setup.

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3.3.4.2. Remote I/O

The CPU shall be capable of communicating with remote I/O over separate remote I/O links.

- Communication links between the CPU and any remote I/Os shall be either triplicated twisted, shielded pairs or triplicated fiber optic cables.
- The minimum communication rate between the CPU and remote I/O shall be no less than 57K baud.
- The communication distances between CPU and remote I/O shall be:
  - 100 feet using standard wiring, i.e. no additional interfaces
  - Up to 10 kilometers using interfaces for fiber optic or other enhanced transmission methods

3.3.4.3. Multiple Networks

- The CPU shall be capable of supporting multiple networks.
- Each CPU shall be addressable on each network with a unique address.

3.3.4.4. Compatibility

The CPU shall support IBM or PC-compatible software to program online and offline, download, store, edit, monitor, document and print ladder logic. Document and print functions of the software shall allow element labeling, rung comments, cross-referencing, I/O and register listings, etc.

3.3.4.5. TMR-PES Interface

The software shall support communications from the PC to the TMR-PES through the standard communication port of the PC, without requiring special PC boards. The CPU shall support up to four RS-232 or RS-422 ports.

The TMR-PES shall be designed so that no more than 50 percent processing capability and memory is used in the CPU at the completion of the TMR-PES Factory Acceptance Test.

3.3.4.6. I/O Scan

The CPU shall continuously scan the control program stored in memory, the status of all inputs and execute specified commands to appropriate outputs. Composite input scan, program execution and output state transition time shall be less than 50 milliseconds.

3.3.4.7. SOE Recording

Sequence-of-Events (SOE) recording shall time tag each discrete signal in the order of occurrence with a minimum resolution of 10 milliseconds. The PES shall transfer SOE data to an external computer for monitoring or

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printing. SOE shall include recording of faults internal to the system (CPU, I/O module, communications faults, etc.).

3.4. CPU Operating Modes

3.4.1. Key-Lock Mode

A key-lock mode-select switch and password on each CPU chassis shall prevent memory modification from any outside source. The key-lock switch shall allow optional modes, including Program, Remote, Run, Lock/Unlock or other equivalent functions.

3.4.1.1. Program (Unlock) Mode

In the Program or Unlock mode, it shall be possible to load programs locally or remotely; create, modify or delete ladder and data files; download to a memory module; and save and restore programs. It shall be possible, through the use of special commands, to disable selected inputs and outputs.

3.4.1.2. Run Mode

In the run mode, normal operation shall occur with the inputs and outputs active, as well as the CPU and the program running. It shall be possible to save programs to an external device. It shall not be possible to create or delete ladder or data files, program online, modify the size of the data file or change processor mode of operation through an external programming device or communications interface while in the Run mode.

3.4.1.3. Remote Mode

It shall not be possible to create or delete ladder or data files or alter application program memory contents while in the Remote mode.

3.5. Status Indication

The CPU shall continuously monitor its own status and indicate both normal operation and error conditions via LED status indicators (or equivalent) on each CPU module faceplate. In addition, all fault conditions shall be annunciated both locally (CPY faceplate) and remotely (at operators terminal), and be capable of being logged on a printer.

As a minimum, the following status indications shall be provided (or the equivalent):

FORCE	Any I/O which is in a force on or off condition
COMM ACTIVE/FAULT	Communication status
PROC RUN/FAULT	Faulted conditions within the CPU
REMOTE I/O ACTIVE FAULT	Status of remote I/O

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BATT	Status of battery backing up RAM

3.6. Fault Tolerance and Self-Checking

The system shall be fault tolerant; no single fault shall adversely affect the proper operation of the SIS. Redundancy shall be established throughout the system to ensure that there shall be no single point of failure.

Removal or failure of modules within the TMR-PES shall be automatically detected, identified and alarmed via output contacts, diagnostic status words and LED's (or equal) without interruption of normal processing functions.

3.6.1. Automatic Self-Tests and Diagnostics

Internal logic within each CPU shall incorporate automatic self-test and diagnostic routines, I/O change-of-status/loop-back verification and data table fault detection to determine the health of each module or sub-assembly within the TMR-PES. Comprehensive fault detection shall be performed using two-out-of-three voting and fault detection circuits in both firmware and software. These circuits shall automatically identify, alarm, isolate and contain faults without compromising TMR-PES performance. The software overhead necessary to run diagnostic routines shall in no way interfere with application program scan or execution time.

3.6.2. System Status Alarm

A failure or fault indication on any I/O device shall initiate a system status alarm on the operator consoles, cause an orderly changeover to a redundant unit (if necessary) and cause its particular input power source to be interrupted or isolated.

3.6.3. Processor Faults

If any processor fails to agree with the other two processors, the failed processor shall be automatically diagnosed and alarmed as having failed. The other two processors shall continue to operate with no degradation to TMR-PES operation. If a second fault occurs in one of the two remaining controllers before the first controller is replaced or repaired, the TMR-PES shall be configurable to continue to operate with one processor (3-2-1 mode) or to shutdown to a predefined, fail-safe, de-energized state (3-2-0 mode).

3.7. I/O Modules

3.7.1. Triplication

All inputs shall have a triplicated path to the processors and all outputs shall be triplicated from the processor to the process shutdown output terminals.

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Inputs and outputs from duplicated or triplicated process measurements and shutdowns shall be connected to separate input cards to preclude a single point of failure.

3.7.2. LED Indicators

Discrete Input modules shall have status LED's for each circuit. The LED's shall be powered from the loop voltage. All other I/O modules shall have single LED indication for module fault status. Modules using circuit integrity monitoring shall be equipped with LED status for each channel.

3.7.3. Optical Isolation

Internal circuits of each I/O shall be optically isolated from external power circuits and protected from power surges and transients. Refer to IEEE C37.90.1.

3.7.4. I/O Fuses

Each discrete input and output point shall be individually fused via slow-blow fuses and rated at the system circuit protection requirements. Discrete input points may have rail mounted fused terminal blocks in the system marshaling cabinet. Discrete outputs for Fire and Gas (F&G) systems shall have two fused terminal blocks for each DO point with a zener diode between the terminals. All individual discrete I/O fuses shall be located in areas readily accessible for maintenance. Removal of I/O modules shall not be necessary to accomplish fuse replacement.

3.7.5. I/O Module Insertion and Removal

I/O modules shall be capable of being inserted in or removed from their chassis without disturbing external wiring. Field I/O wiring shall be connected to remote termination panels via integral screw type terminals.

3.7.6. Overrange Protection

Analog input modules shall provide overrange protection.

3.7.7. Module Orientation

The I/O section shall be designed so that all I/O modules are oriented vertically within the I/O chassis. I/O modules shall be capable of being arranged in any location within a chassis, irrespective of their voltage level.

3.7.8. Module Faceplates

I/O modules shall have faceplates for labeling and marking in accordance with the wiring diagrams.

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3.7.9. Interlocks

Each rack position shall have an electronic and/or mechanical interlock that is unique for each type of I/O module. This shall prevent the insertion of an incorrect module.

3.7.10. Electrical Isolation

The minimum isolation requirements between electrically separate circuits shall be 300 volts.

3.7.11. Spare I/O Points

The system shall be designed for addition spare I/O points without having to shutdown the system.

3.8. External Communication

The TMR-PES shall support multiple RS-232, RS-422 or RS-485 ports for bi-directional communication with external devices such as the host computer, local area network, program development station, distributed control system or printer.

3.8.1. Security

All communication ports shall permit connection and disconnection without interrupting or jeopardizing SIS operation. The TMR-PES CPU memory contents shall be write-protected from alteration by a combination of either key lock or password security techniques. In addition, failure of a communications system device shall not affect or prevent other devices on the communications system from operating.

3.8.2. Functions

External communications shall operate redundantly and support the following functions:

- Downloading of programs and SOE configuration via a password protected and/or key-locked protection mechanism
- Uploading real-time SOE records
- Reading/writing program data
- Monitoring fault status
- Forcing inputs
- Direct printer interface for reporting/printing "sequence of events" or internal program alarms.

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3.8.3. Operator Interface

All process inputs and outputs to and from the TMR-PES shall be capable of being displayed to the operator via the DCS or dedicated workstation located in the main control room via the external communications interface. The operator interface shall not allow access to the application program or affect the operation of the TMR-PES in any way.

3.9. Enclosures

TMR-PES enclosures shall be NEMA 12 rated, free standing and constructed to withstand moving, installation and normal platform vibrations.

- System cabinets shall house power supply modules, I/O modules, CPUs, communication modules, remote I/O interface modules, etc.
- Where I/O marshaling cabinets are supplied as part of the system, they shall house field terminal strips, intrinsic safety barriers and I/O termination boards. The TMR-PES vendor is responsible for the integration and function of all elements in the supplied system. Lightning/surge arrestors shall be provided on the I/O where specified.
- All TMR-PES system cabinets and marshaling cabinets shall be 32"d x 32"w x 78"h, free standing, front access only with bottom cable entrance.
- All marshaling cabinets shall have removable bottom gland plates to provide a termination point for field incoming metal clad instrumentation cables.
- The paint color and finish shall be the vendor's standard colors.
- Doors on cabinets and workstations shall be fitted with seals for dust exclusion.
- Doors shall be roller type where practical. Hinged doors shall have lift-off type hinges.
- All doors shall be lockable and be provided with the same lock and key combination. Keys shall be removable only with the doors locked. Each cabinet shall be supplied with at least two keys.
- All holes or openings that are not used shall be suitably covered or sealed.
- The cabinet shall be fitted with readily accessible and removable filter screens.
- Cabinets shall have 3 inch minimum spacing around terminal blocks for ease of termination and sufficient space for routing and bending of cables and/or conductors.

3.9.1. Component Mounting

Card/rack installation shall facilitate quick replacement of components. Card mounting and supports shall be designed to dampen the effects of external vibration on installed modules and components. Components not mounted

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on printed circuit boards shall be securely fastened to a chassis or bus assembly.

3.9.2. Circuit Protection

To protect power supply and I/O circuits, fuses and circuit breakers shall be properly sized in accordance with NFPA 70 or the manufacturer's guidelines. Breakers and fuse blocks shall be properly labeled.

3.9.3. Grounding

- The vendor shall provide an isolated ground bus for connection to the SIS Instrument Signal Ground (ISGN) at the bottom of each TMR-PES cabinet. The ground bus shall consist of a copper bar that is suitably drilled and tapped for screw terminals and wire lugs. A No. 8 AWG screw-type compression lug shall be provided at both ends of the ground bar for connection to the ISGN.
- Each cabinet shall be provided with a safety ground lug for connection in the field to the safety earth system.
- Each door panel shall be electrically bonded to the main cabinet by a braided ground strap (minimum wire size equivalent to #8 AWG).

3.9.4. Lift Rings

Each cabinet shall be provided with removable lifting rings.

3.9.5. Lighting and Ventilation

An overhead incandescent light shall be furnished in each cabinet to allow sufficient illumination for wiring, trouble shooting or I/O replacement. Exhaust fans shall be furnished for adequate ventilation and cooling for system modules. The lights and fans shall be powered by an external, non-essential 120 VAC power supply. The system shall be designed to operate without forced ventilation.

3.9.6. Keyed Components

All removable components shall be keyed and labeled to facilitate reinsertion in the correct slot and preclude insertion in the incorrect slot.

3.10. Power Supply

External power to the system shall be 240 or 120 VAC and originate from an Uninterruptible Power Supply (UPS).

- This power shall be converted to 24 VDC in redundant supplies.

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- The 24 VDC sources shall be the operating power for the TMR-PES.
- Twenty-four volt DC battery backup shall be provided where special needs exist. For example, fire and gas detection may be necessary long after the one-hour battery backup from the UPS is exhausted.
- Each power supply shall be separately connected to a separate internal bus.
- The TMR-PES vendor shall distribute redundant DC loop power within the system to power all two-wire analog inputs and outputs, discrete inputs and discrete outputs.
- Power distribution and protection, filtering and conditioning, power supplies, bus bars and power wiring, etc. shall be within the supplied PES.
- The TMR-PES power supplies shall be rated for 150 percent of the maximum calculated TMR-PES load including 25 percent spare modules, with all modules and outputs energized and carrying their maximum rated load.
- Each power supply shall operate on its own internal fuse with circuit protection. There shall be an alarm for each power supply failure.
- Power supply modules shall be duplicated per I/O rack as a minimum.
- Each system cabinet shall have a 120 VAC receptacle outlet with power switches.
- Variation of the applied power of 85–110 percent nominal value shall not affect the operation of any circuit in the system.
- The system shall be internally protected against system errors and hardware damage resulting from connecting and disconnecting devices, or removing or inserting printed circuit boards in the system.

4. I/O Requirements

4.1. General

The TMR-PES may be divided in two or more areas that house I/O module cabinets.

- Each system I/O cabinet may have two or more groups of I/O modules. In general (see Section 3.1), process shutdown I/O modules shall not be on the same chassis as non-process I/O modules, (i.e., fire and gas), but may share the same power supplies, processors and I/O communication bus.
- Each TMR-PES I/O cabinet shall contain 25 percent spare I/O, completely wired from the field termination strips, to the barriers and then to the I/O respective I/O modules. The TMR-PES I/O racks shall contain 15 percent installed spare I/O modules per module type. The I/O modules shall be distributed throughout the I/O racks. A minimum of one spare module for each different type of module shall be provided.

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4.2. I/O List

A PES I/O list (separate from the Project Instrument List) shall be compiled and include, as a minimum:

- Tag number
- PID
- Location
- Service description
- Instrument type
- I/O type
- Module and terminals
- Actuation condition (trip point)

5. Wiring and Terminations

5.1. Wiring

- Wiring inside cabinets and workstations shall be run in dedicated plastic ducts or wireways properly bundled and secured with plastic spiral wrapping or tie-wraps and anchors.
- Spare space shall be provided in the wireways and where wiring is laced to accommodate 100 percent additional wiring.
- All cables shall be adequately supported and shall be provided with a strain relief mechanism for cable connectors.
- Segregation between AC and DC wiring shall be accomplished by separating wireways or bundled cable bundles a minimum of 3 inches.
- Where intersections between AC and DC wiring occur, care shall be exercised to make the intersections at right angles, with maximum possible separation.
- Field wires shall be connected so switching is always on the hot side of the line.
- Thermocouple wiring shall be terminated to thermocouple terminal panels or directly to the input card.

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5.2. Terminal Blocks

Terminal blocks and terminal block connections shall meet the requirements of MP 32-P-21.

- All terminal blocks shall be Weidmuller non-brittle polyamide 6.6 material (or equal) and be suitable for rail mounting with compression type conductor terminations.
- Terminal blocks used for input and output signal wiring shall use fused disconnect knife switch (make or break) type terminals. Fuses shall be sized appropriately for the application. Fuses shall be installed in both legs.
- Adequate space shall be provided to prevent touching electronic hardware when working at terminal blocks.
- There shall be 10 percent spare terminal blocks for each cabinet or cabinet area containing terminal blocks.

5.3. Cabling

- All interconnecting communication cables between cabinets and printers, operator workstations, engineering workstations, etc. shall be part of the supplied PES.
- If multi-core cables are used for I/O wiring between or inside cabinets, the cables shall meet the requirements of MP 32-P-21.
- Wiring lists shall identify all wiring to connector pins.
- Cable entry for power, grounding and interconnecting cables for cabinets and workstation shall be from the bottom.

5.4. Nameplates and Tagging

Each cabinet, workstation, card file, device, terminal strip, terminal and interconnecting cable end shall be clearly marked with permanent identification.

5.4.1. Cabinet and Device Labels

- Cabinet and device labels shall be permanently affixed to the assembly with fasteners or bonding and shall be of laminated plastic or approved equal with white-black-white (information engraved into black core with white surface, dull finish) as per the nameplate schedule.
- Each cabinet shall have a cabinet identification label on the front and also a nameplate listing all of the devices within the cabinet, their function and their location. These labels shall be capable of easily being changed for future additions.

- In addition, the TMR-PES cabinet nameplates shall bear the information listed in Items a–e below. Also, all TMR-PES modules shall bear the information listed in Items a, b, c and f, where applicable. TMR-PES module nameplates shall be the vendor's standard.

  a) Manufacturer's name and trademark

  b) Part/model number/revision level

  c) Serial number (if applicable)

  d) Purchase Order number

  e) Company's mark/ tag number

  f) Electrical supply voltage and current

5.4.2. Circuit Breakers

Each circuit breaker shall be tagged with a permanently mounted nameplate that identifies its supply source (voltage, panel and circuit number).

5.4.3. Wires

All wires connected to terminal block terminals, including I/O module termination panels, shall be tagged with two identification tags.

- The first tag (closest to the end of the wire) shall identify the terminal number to which the wire is physically connected.
- The second tag shall identify the terminal or device number to which the opposite end of the wire is connected.

Wire markers shall be slip-on, heat-shrink, permanently embossed, sleeve type. Wrap-around, self-adhesive type markers are not acceptable.

5.4.4. Terminal Blocks

Each terminal block shall be labeled with a sequential terminal identification number for input or output signal wires.

Each row or column of terminal blocks shall be labeled with a unique identification name or number.

5.4.5. Connector Plugs

Multi-core cables with connector plugs shall be labeled with two identification tags.

1. The first tag (closest to the plug) shall identify the device and socket to which the plug is to be connected.

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2. The second tag shall identify the socket or device to which the opposite end of the cable is connected.

5.4.6. Controls and Indicators

All instruments, push buttons, switches, lamps, etc. shall be identified by two identical labels, one on the front (outside) of the panel and one on the back (inside) of the panel.

- All nameplates shall be mounted immediately below the corresponding instrument or accessory, unless specified otherwise.
- The labels shall be made of plastic or stainless steel and inscribed with tag number and service.
- The nameplates shall be attached with non-corrosive fasteners or approved adhesive.

6. Hardwired Inputs And Outputs

PSD analog inputs such as level, pressure and temperature transmitters shall be 24 VDC, 4-20 ma loop powered from the TMR-PES analog input module. The PSD analog input module shall be able to read the 4-20 ma, 24 VDC signals from field powered devices.

PSD discrete inputs from switches or unit control panels shall be voltage free contacts. For circuit integrity, the TMR-PES shall be capable of monitoring an end-of-line device for each discrete input. If use of circuit integrity monitoring for discrete outputs is used, ensure that end devices are suitable types.

7. Engineering and Operator Console and Printers

Engineering consoles and operator workstation (operator workstation requirements stated herein are only for an operator interface not supplied via the DCS) shall be per the recommendations of the Human Machine Interface (HMI) vendor.

All operator and engineering consoles shall be desktop type with 21 inch high-resolution super-video graphic-array color monitor (1024 x 768 Resolution, 65525 colors) keyboard and pointing device.

There shall be a minimum of two TMR-PES printers. One printer shall be set for alarm and the other shall be for engineering use or for printing sequence of event reports. All printers shall be the same type and size as the DCS printers.

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The PES Operator Consoles shall provide graphic screens which display status of all I/O alarms, by-passes, shutdown system conditions, fire and gas detection system and fire water pumps.

8. Programming and Software Configuration

The vendor shall provide program development software tools and hardware interface enabling the applications programmer and user to develop, edit or debug application programs.

8.1. Application Software

The engineering programming software shall comply with IEC 61131-3. Other formats (e.g. Boolean statements, flow charts, code or mnemonic language) may be included as additions.

8.1.1. Editing Capability

The editing capability shall allow correction of any rung at any time without the need to re-enter the entire rung. It shall be possible to add or delete logic elements to or from any location within the ladder diagram.

8.1.2. Basic Instructions

Basic instructions shall include "force" (disable) instructions bypassing the logic elements and providing manual override of the system to allow for commissioning and troubleshooting, as well as latching and unlatching outputs.

8.1.3. Inserting Elements

It shall be possible to insert relay ladder diagram rungs anywhere in the program, even between existing rungs, insofar as there is sufficient memory to accommodate the additions. It shall allow change of contact type, add extra contacts and change address without requiring reprogramming the entire program.

8.1.4. Display

On the relay ladder run display, its shall be possible to show the online running open/closed status of inputs and energize/de-energize status of outputs.

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8.1.5. Online Modifications

The TMR-PES shall have the capability for users to perform online configuration and modification of a program without shutting down the TMR-PES processors for downloading changes to the program.

8.1.6. Security

The application software shall provide protection at multiple security levels through user name and password to various programs.

8.1.7. Ladder Instruction Set

The following ladder instructions or elements shall be provided as a minimum by the TMR-PES vendor.

1. Math instructions: Add, Assign, Divide, Multiply, Square Root, Subtract, etc.
2. Data manipulation: And, Or, Shift Left, Shift Right, Binary-to-Decimal Conversion, Decimal-to-Binary Conversion, Conversion of Analog Input to Real (Floating Point) Number, etc.
3. Program control instructions: Call, Jump, Label, Return, Do Loop, If/Then, etc.
4. Comparison elements: Less Than (<), Greater Than (>), Equal To (=), Not Equal To (≠), Less Than or Equal To (≤), Greater Than or Equal To (≥), etc.
5. Timer and counter elements: Count Up, Countdown, Time Delay, Time Up, Time Down (with accumulator, preset and time-base sub-elements), etc.
   - Time base from .01 second to hours
   - Counter scale factors from x1 to x1000.
6. Relay contact elements: Normally Open (NO), Normally Closed (NC), etc.
7. Relay coil elements: Momentary, Latch, Unlatch, etc.
8. Control algorithms: Proportional-Integral-Derivative, Lead-Lag

8.1.8. Ease of Use

The application program shall be designed to promote user friendliness for operations and maintenance personnel. This implies that sufficient comments and descriptions shall be included throughout all ladder networks or relational elements to communicate element tag numbers, description and intended functionality. Ladder/logic networks shall be arranged to group all logic dealing with a specific piece of equipment of function.

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8.2. Man-Machine Interface (MMI) Software

MMI Software shall be user-friendly for operators. MMI Software shall operate under a Microsoft Windows platform. It shall be Wonderware or approved equal. Graphic sketches shall be submitted to the Company for approval prior to program implementation.

MMI Software shall provide password protection at multiple security levels. There shall be a built-in security system controls access by user name and password to programs at various functional levels. Users' access rights can be added and deleted, as well as changed through the MMI software.

8.3. Bypass Switches

The TMR-PES shall contain no output bypass switches. The TMR-PES shall incorporate software configured input bypass switches for each field device to permit its testing and maintenance.

All input bypass switches shall not prevent outputs from being de-energized in response to activation of a manual TMR-PES switch. In general, input bypass switches shall not bypass nor disable outputs to annunciators, CRT alarm displays or data loggers.

The operation of input software bypass switches shall be alarmed and logged by the TMR-PES or other annunciation/data logger system via the external communication interface device.

9. Inspection and Testing

9.1. Pre-Acceptance Tests

The TMR-PES vendor shall conduct a comprehensive hardware test prior to any acceptance tests. All TMR-PES modules shall have gone through a Heat-Soak and Burn-In test. The TMR-PES components Heat-Soak and Burn-In testing shall be no less than 72 hours in an controlled environment with the temperature varying from 32–140°F and the relative humidity varying from 20–90 percent.

9.1.1. Hardware Reliability Test

- Two events, failure and repair shall determine the reliability of TMR-PES modules. The availability, A, of a module can be predicted from its mean time to failure (MTTF) and mean time to repair (MTTR) values as follows:

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A = (MTTF / [MTTF + MTTR]) x 100 percent

- The availability of the composite TMR-PES shall be 99.95 percent or better. The vendor shall provide detailed calculations of the availability of the total TMR-PES and the mean time between failure. The methods used shall be based on MIL HDBK-217F (latest edition) or equivalent.

- Only superficial testing of a system's long-term reliability is possible during the relatively short testing periods at the factory and after installation on site. These testing periods occur early in the life of a system, long before the MTTF for the majority of systems modules. Hence, the number of failures occurring during the brief test period for any type of module in the system should be extremely low. Confidence levels shall be established for each module delivered with the system. The maximum number of modules of the same type allowed to fail during tests, F, shall be calculated by the following formula:

F = (number of modules)(Testing hours) x (1-[Avail/100]) (MTTR hours)

9.1.2. Software Reliability

Prior to Acceptance Test, the vendor shall conduct a formal testing of all operating and application software. The test shall be based on approved Software Reliability test procedures. As a minimum, the vendor shall base the test procedures on recognized industry standards such as IEEE 730, IEEE 828 and IEEE 1042. Test procedures, including reference standards, shall be included in the quotation and provided by the vendor as part of the Pre-FAT and/or FAT test procedures.

9.2. Acceptance Tests

The TMR-PES Acceptance Tests shall be conducted, signed and approved by the Company or its representatives in three stages:

1. The Factory Acceptance Test (FAT) or Staging Test
2. The Site Acceptance Test (SAT)
3. The Sustained Performance Test (SPT)

The TMR-PES vendor shall submit for review and approval, a complete plan for the vendor's factory and site acceptance testing. This plan shall detail the nature of each test, time required, expected results and step-by-step procedure. The plan shall include the hardware and software reliability testing requirements outlined in Sections 9.1.1 and 9.1.2. The plan shall be submitted at least two months in advance to allow sufficient time for review and approval.

9.3. Factory Acceptance Test (FAT)

The objective of the FAT is to verify that the TMR-PES as configured for delivery meets or exceeds the specified design and functional requirements. The test shall be conducted

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at the TMR-PES vendor's staging site and shall be tested according to the Factory Acceptance Test procedure produced for the project.

During the FAT test, the complete TMR-PES, including all composite modules and interconnecting wiring, shall be subject to both hardware and software functional tests.

The hardware inspection and function testing shall include the following:

1. Function tests of each individual component module within the integrated TMR-PES, including operation of the power supplies, module replacement and standby changeover, operation of communication devices, workstation and printer operation. Fail safe output states shall be tested in response to simulated Input/Output module and CPU failures and loss of TMR-PES module power. All diagnostic routines shall be tested by simulating CPU and I/O module/individual point failures, communications interface failures and card replacement induced failures. Fault histories/summaries shall be logged and annunciated both on an external printer and an operator's workstation or console. The test shall include a simulated loop test of each type of loop including the actual end devices.
2. Ground Fault Detection test as required.
3. System Responsiveness test to determine scan rates, alarm generation and logging.
4. A comprehensive vendor inspection including system configuration according to drawings, spare capacity verification, wire tagging and terminations shall be checked as well as "tug" testing of wires. (A tug test involves physically stressing a wire termination to determine whether it has been crimped and terminated properly. The intent is not to break wiring or stress insulation but to test the integrity of the termination.)

All software logic application programs shall be checked against logic drawings and dynamically tested and verified for proper sequence and functionality. The Dynamic test shall involve physically simulating all inputs and outputs in their proper operational sequence and verifying that specified TMR-PES application program logic is executed properly. All Sequence of Events (SOE) functions shall be demonstrated for randomly generated input event cycling, with the specified point resolution being demonstrated. The vendor shall provide manual switching/indicator panels to simulate input/output. Automated switching and feedback shall be provided where necessary.

9.4. Site Acceptance Test (SAT)

The objective of the SAT is to verify that TMR-PES installed at the project location meets or exceeds the specified structural and functional requirements. The SAT shall be conducted in two phases.

- The first phase shall consist of post installation inspection and software module testing.
- The second phase shall be an abbreviated version of the FAT. The vendor shall verify that all equipment, interconnecting cables, external power connections, inverters,

operator consoles, engineering workstations and grounding connections have been installed and operating properly.

The vendor shall also test the data communication cables installed by others.

9.5. Sustained Performance Test (SPT)

The objective of the SPT is to determine the long term stability and availability of the TMR-PES under normal operating conditions. It shall also verify the TMR-PES ability to clearly report any and all malfunctions and the vendor's ability to diagnose and fix any problem in a timely manner.

- The test commences when the TMR-PES protects a portion of the process as specified by the Company.
- The Company shall conduct the SPT over a sustained period of 30 consecutive days (or longer under agreed conditions).
- The criteria for success shall include at least 99.995 percent availability (in the standard statistical sense) and not more than one hardware and/or software failure during the 30 day period.
- A "failure" is defined as any occurrence preventing full use of the TMR-PES.
- Availability shall not be affected and the SPT shall be temporarily suspended in case of any failure caused by the Company supplied equipment or services.

9.6. Inspections

The Company or its designated representatives shall be entitled to inspect equipment, materials and any part at the vendor's or vendor's sub-supplier's premises during any phase of manufacturing.

- Inspection visits shall be coordinated through the vendor's Project Manager.
- The Company shall have access to all quality control and other records that document design, testing and integration of the system.
- Photographs and videotaping shall be permitted during system assembly to record progress of manufacture, with reasonable advance notices.

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10. Documentation

10.1. General

The vendor shall furnish adequate drawing and documentation. As a minimum, the documentation shall include a Design Manual with the following contents:

1. List of equipment and accessories on system drawings
2. System overview drawings, cabinet and console layout drawings
3. Outline dimensions, mounting details, interconnection drawings, cable lists, weights, heat loads and power requirements for all equipment
4. Module arrangement, insert drawings and internal arrangement drawings for all system cabinets
5. Itemized cable list with cable lengths, TO/FROM destinations and cable identification
6. Detailed power distribution diagrams for all power levels within the system including circuit breaker power entries, plug and mold strips for power distribution within the workstations and system cabinets
7. Detailed grounding diagram for the system
8. Test plan
9. An index of all documentation provided for the system

10.1.1. Installation and Maintenance Documentation

The vendor shall provide installation and maintenance manuals providing detailed procedures for the installation, maintenance and troubleshooting of all TMR-PES equipment. The vendor shall provide operating and programming manuals describing operating modes, programming procedures, parameters and guidelines.

10.1.2. Bills of Material

The vendor shall furnish a complete bill of material on all purchased items and a complete system spare parts list.

10.1.3. Company and Project Identification

All documentation shall have the Company's project number, a documentation identification number, optional project number, the issue date,

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and revision identifiers in English. The Company requires unlimited internal copying rights to all project documentation supplied.

10.1.4. Electronic Files

Floppy disks containing word processor files of the manuals listed above shall be optionally available. AutoCAD files shall be optionally available for the final version of all project drawings.

10.1.5. Updates

The vendor shall provide documentation updates for any and all system upgrades, modifications, documentation error or bugs discovered by the Company, the vendor or others purchasers of the vendor's products that have been purchased under this Practice. The vendor shall provide these updates through to the expiration of the warranty and any extended service or maintenance agreements purchased.

10.1.6. TMR-PES Availability

Detailed specifications and calculation of overall TMR-PES availability within the constraints of this document, including failure modes and effects analysis shall be provided.

10.2. Vendor's Services

The vendor shall provide appropriate documentation if configuring, programming and other related project engineering services are conducted by the vendor. As a minimum, these shall include:

1. A listing of the I/O address and configuration identifying each module type, location and tag name.
2. Annotated printouts of all ladder logic programs and its associated files. Ladder logic shall include completed I/O addresses and logic element parameter identification to facilitate TMR-PES troubleshooting.
3. An Index of the system's database including tag names, descriptions and initial values.
4. I/O and internal element cross reference.
5. SOE configuration file and record.
6. A complete narrative describing the operation and sequence of the logic system.

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Instrumentation for Watertube Steam Boilers

MP 32-P-12

July 1998

Scope

This Mobil Engineering Practice (MEP) supplements the requirements of NFPA 8501 and NFPA 8502 for fired boilers, covering the basic requirements for the automatic control and protection of watertube steam boilers and describes the instrument systems necessary for the safe startup, operation and shutdown of watertube fired boilers. It also describes the operational organization of the controls, the preferred technology and references the relevant industry standards.

Version 0

Table of Contents

Scope **1**

1. References **4**

1.1. MEPS–Mobil Engineering Practices 4

1.2. Mobil Data Sheets 4

1.3. API–American Petroleum Institute 4

1.4. ASME–American Society of Mechanical Engineers 4

1.5. NEMA–National Electrical Manufacturers Association 5

1.6. NFPA–National Fire Protection Association 5

1.7. SAMA–Scientific Apparatus Makers Association 5

2. System Description **5**

2.1. Functional Organization 5

2.2. Operator Control Interfaces 6

3. System Design **8**

3.1. Industry Standards 8

3.2. Design Responsibility 8

3.3. Burner Management System (BMS) 9

3.4. Modulating Controls 11

3.5. Fuel and Air Measurements 11

3.6. Sootblowers 12

3.7. Level Control and Shutdown on the Steam Drum 14

3.8. Level Gauges on the Steam Drum 16

3.9. Desuperheater Controls 17

3.10. Safety Trip Valve 18

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3.11. Annunciation and Event Logging 18
3.12. Signal Communications 19
3.13. Shutdown (Chopper) Valves 19
3.14. Relief Valves 19
3.15. Power Supplies 20
3.16. Panel Construction 20
3.17. Analyzers 21
4. Testing 21
Modifications to API RP 556 22
Appendix: Instrument List 26

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1. References

The following publications form a part of this Practice. Unless otherwise specified herein, use the latest edition.

1.1. MEPS–Mobil Engineering Practices

MP 11-P-22	Waste Heat Steam Generators-Design & Fabrication
MP 32-P-06	Process Analyzers
MP 32-P-07	Safety Interlock Systems and Alarms

1.2. Mobil Data Sheets

Mobil Data Sheets	Mobil Data Sheet Home Page
D3212C01	Instrumentation for Watertube Steam Boilers - Documentation Requirements Sheet

1.3. API–American Petroleum Institute

API RP 556	Fired Heaters & Steam Generators
API RP 598	Valve Inspection and Testing (out of print)
API STD 607	Fire Test for Soft-Seated Quarter-Turn Valves Fourth Edition

1.4. ASME–American Society of Mechanical Engineers

ASME SEC I	BPVC SECTION I Rules for Construction of Power Boilers Addenda - 1995; Addenda - 1996; Interfiled (Boiler and Pressure Vessel Codes)

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1.5. NEMA–National Electrical Manufacturers Association

NEMA SM 23	Steam Turbines for Mechanical Drive Service

1.6. NFPA–National Fire Protection Association

NFPA 8501	Standard for Single Burner Boiler Operation (Formerly NFPA 85A)
NFPA 8502	Standard for the Prevention of Furnace Explosions/Implosions in Multiple Burner Boilers Revision and Renumbering of ANSI/NFPA 85C-1991; Errata 03/01/1996

1.7. SAMA–Scientific Apparatus Makers Association

SAMA PMC 22. 1	Functional Diagramming of Instrument and Control Systems (out of print)

2. System Description

The automatic control and protection of watertube steam boilers and the instrument systems necessary for the safe startup, operation and shutdown of watertube fired boilers shall be designed and operated in accordance with requirements of this MEP, unless superceded by more stringent local regulations.

2.1. Functional Organization

The boiler controls are functionally organized as described below. These controls are interconnected with each other to provide a complete coordinated system covering all modes of operation of the boiler.

2.1.1. Safety, Startup and Shutdown

The Burner Management System (BMS) monitors the safety, startup and shutdown of the boiler.

- On detection of an unsafe condition, it shall shut the boiler down safely.
- In a multiburner system, it shall shut down the faulty burner only.

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2.1.2. Dynamic Performance

After the boiler has been started, its dynamic performance is monitored by a dedicated system referred to as the "modulating controls." The performance and duty of the boiler shall be adjusted through the use of these controls.

Controls included in this system are:

1. Combustion
2. Boiler drum level
3. Steam pressure
4. Steam temperature

2.1.3. Sootblower Sequencing System

The Sootblower Sequencing System is a peripheral system dedicated to controlling and monitoring the operation of the sootblowers.

2.2. Operator Control Interfaces

Control system operator interfaces provided for either single or multiple fired boilers are described below. These procedures shall be varied to meet local requirements for specific boilers with Mobil approval.

A summary list of the indicating and control instrumentation is provided in the Appendix of this Practice. This list does not necessarily include all of the instrumentation that shall be provided to achieve a safe operable system, nor is it intended that all of the instrumentation listed is always required. However, the listed requirements shall not be reduced without approval. This list can be used as a check list during the boiler selection process and modified as required to ensure consistency with the boiler being procured, local codes and practices and the plant operational philosophies (e.g., manning, alarm management, control centers, etc.).

2.2.1. Control Room

There shall be a control room used for the day-to-day running of the boiler(s).

- The control interface provided in the building shall be a Distributed Control System (DCS) and consist of Cathode Ray Tube (CRT) displays and keyboards.
- There shall also be conventional switches and possible conventional annunciation (depending on the alarm philosophy of the specific operating unit).

The following is a summary of the operator interfaces provided at this location:

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1. The operational status of all modulating controls shall be provided via instrument faceplates and graphics by CRT displays.

    a) Firing rate of the boiler shall be adjusted and the operational mode of the boiler changed using these controls.

    b) More details are provided on the modulating controls in subsequent Sections of this Practice.

2. The operational status of the firing process and the running status of the boiler, derived from the BMS via serial links and/or hardwired connections to the DCS, shall be shown on the operator CRT display. Additional details on the BMS are provided in subsequent Sections of this Practice.

3. Alarms, shutdown annunciation and logging.

4. A boiler emergency shutdown switch for each boiler.

2.2.2. Local Control Panel

A local panel shall be provided and located adjacent to each boiler front and fuel rack and used for the startup, firing and initial steam production prior to transferring control to the control room. A single operator shall be capable of firing (starting up) the boiler from this panel.

The local panel shall include:

1. Controls to prepare the boiler for startup (e.g., filling the steam drum)

    a) Usually in the form of local auto/manual stations forming part of the modulating controls and interfacing directly with the DCS

    b) It is likely that these will be enabled only when the boiler is shutdown

2. BMS provided switches and lights to facilitate a supervised manual firing of the boiler

3. BMS provided switches for shutting down, adding and changing fuels

4. Controls for bringing the steam up to initial pressure and transferring control of the boiler from the local control panel to the control room and finally to the plant steam system

    a) Usually in the form of local control display station forming part of the modulating controls and interfacing directly with the DCS

    b) The control function is always in the DCS with the display station providing facilities for set point changes, auto-manual and local-remote switching

5. Annunciation to monitor the alarm and shutdown status of the boiler

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6. A boiler emergency shutdown switch that interfaces directly with the BMS

2.2.3. Combustion Air-Forced Draft Fan Panels

Normally, a local panel shall be adjacent to each fan. This panel shall include startup, shutdown and monitoring facilities for the fan including the following:

1. Annunciation to monitor the alarm and shutdown status of the fan
2. Driver speed indication (only required when the fan and driver run at different speeds)
3. Fan speed indication
4. Drive start pushbutton (electric drives)
5. Vibration information
6. Emergency stop
7. Lube oil system alarms and pressure indication

2.2.4. Sootblowers

Sootblowers shall have a dedicated panel on the firing aisle. Alternate locations require approval.

3. System Design

3.1. Industry Standards

Acceptable (mandatory in the US) design practices and functional requirements of a fired watertube steam boiler control system are described in detail in NFPA 8501 and NFPA 8502 and are the basis for the Burner Management System presented by this Practice. API RP 556 and MP 11-P-22 are required references for application of this Practice.

API and NFPA standards overlap, and reference shall be made to both for the entire control system. Should a conflict arise between the two standards, NFPA shall take precedence.

3.2. Design Responsibility

The boiler control and instrumentation systems shall normally be procured as part of the boiler package.

- The boiler supplier shall have total responsibility for all systems.
- If it is expedient for the DCS or the BMS to be supplied as part of a wider project procurement strategy, the boiler supplier shall retain full system responsibility and provide configuration and programming for the entire system.
- The boiler supplier shall subcontract the control systems to specialists in this field.

3.3. Burner Management System (BMS)

This system monitors the safe lightoff and shutdown of the boiler.

- It also incorporates the protection of other components such as the steam drum and the fans.
- The governing standards are NFPA 8501 and NFPA 8502.
- The BMS includes a programmed ignition system.
  - The programmed ignition system is designed to prevent boiler furnace firebox explosions that generally occur during burner ignition, by imposing a safe procedure for startup, purging and restart.
  - Programmed ignition of igniters and burners requires the same steps to be taken at each lightoff.
- The BMS shall be implemented using the latest technology (refer to MP 32-P-07).
  - If local codes do not allow the use of programmable burner management systems, an alternate system shall be used with Mobil approval.
  - The principal operator interface with the BMS shall be at the local panel.
  - Through manual switches, the operator shall be capable of performing a Supervised Manual Lightoff of the boiler in accordance with NFPA.
  - The system used to implement the BMS shall be dedicated to a single boiler.
  - The supplier who provides and programs the BMS shall be an approved Burner Management System supplier.
- The function of the BMS system shall be described in a logic diagram clearly showing the interface with the modulating controls.
  - A block diagram overview and a written description shall also be provided.
- Transmitters, coupled to analog input cards with software switching, are preferred over field-mounted switches for shutdown devices.
  - The outputs of these transmitters shall be monitored in the DCS.
- The use of triplicated shutdown sensors shall be evaluated where the tripping of a single boiler would cause a significant plant upset (reference MP 32-P-07).

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- Triplicated devices are advantageous because they allow one device to be worked on without a maintenance bypass or a shutdown.
- NFPA 8502 requires triplicated devices for furnace pressure control.

3.3.1. Keylock Bypass Switch

For maintenance purposes, provision shall be made for each field shutdown input device to have a keylock bypass switch to manually bypass the shutdown circuit.

- The key can be removed only from the lock assembly in the nonbypassed or "active" position.
- Safety trip valves shall not be bypassed.
- Each bypass switch shall include a local "first out" alarm annunciator with a red status indicator lamp.
- A remote common bypass alarm in the control room shall also be provided.
- When remote instrument enclosures (RIE) are provided, it is preferred to have the maintenance bypass switch panel located in the RIE.
- Bypasses allow maintenance to be carried out during boiler operation.

Forcing logic to allow maintenance is not permitted.

- If triplicated shutdown devices are not used and maintenance is anticipated while the boiler is running, shutdown bypasses shall be provided.
- A maintenance bypass alarm shall also be provided at the local panel and in the control room.

NFPA 8501 Section 4-5.2.2 (g) states, “Any single component failure within logic system shall not prevent a mandatory master fuel trip.”

- To meet this requirement, this Practice recommends an individual TMR/PLC for the logic processor and input/output circuits for each boiler.

Other types of PLCs shall meet the NFPA requirement, but compliance with NFPA 8501 and NFPA 8502 must be demonstrated.

Emergency shutdown of the boiler through the BMS shall also shutdown the sootblower.

Dual redundant solenoid valves shall be required on shutdown valves. Refer to MP 32-P-07.

3.4. Modulating Controls

All modulating controls are implemented in the DCS.

3.4.1. Schematics

A control schematic in the SAMA (Scientific Apparatus Makers Association) style shall be prepared for approval and shall illustrate the following:

1. The function and interrelationship of all of the modulating control systems
2. Local panel indicators
3. Control stations
4. Hardwired connections to the BMS

3.4.2. Joint Control Stations

Control station interfaces directly connected to the DCS shall (see Section 2.2.2 of this Practice) be provided on the local panel to allow the safe start of the boiler.

These control stations shall allow bumpless transfer to and from the control room with the master control at the local panel.

3.4.3. Separate Control Stations

Where there is a separate DCS field control station for each boiler, it shall be possible to take any one of these field control stations out of service and affect only one boiler.

- The controls common to all boilers shall be located in a separate field control station.
- Historical trending of data shall be available for all analog points.
- Care shall be taken to ensure that this meets regulatory requirements, particularly with respect to the recording of emissions data.
- If necessary, a dedicated recorder shall have to be provided.

3.5. Fuel and Air Measurements

Pressure controllers shall be used to maintain constant fuel pressure to the modulating control valves.

- A block and bypass valve shall be installed with each modulating fuel control valve, unless elimination of the bypass valves is approved.

- Fuel gas and fuel oil temperature gauges shall be provided at the burner header.
- A Coriolis type flowmeter shall be used to measure oil flow.
- An orifice plate shall be used for light fuel oils with approval.
- A metering Venturi, airfoil section or Dietrich Standard ASF-76 annubar (or later model) shall be located in the fan inlet or discharge duct.
  - The device shall be capable of generating a differential pressure of 15–250 mm (0.6–10 in) water gauge.
  - Alternative devices shall be subject to approval.
  - If two fans are specified, the metering section shall be installed in the common air duct.

Fan inlet guide vanes shall be equipped with a characterized actuator for automatic control, complete with manual setting and locking devices. A minimum stop shall be provided on the actuator to limit the minimum flow to 25 percent of maximum continuous rating (MCR).

Draft fan controls shall be provided for the air volume required by the burners in modulating from low to high fire and for air purging.

- If the fan is turbine-driven and speed control is specified, the turbine shall be equipped with a NEMA D governor in order to maintain the fan speed required to match the varying load conditions (see NEMA SM 23).
- Normally, a control head with a speed range of 75–105 percent shall be furnished. Other ranges require approval.

3.6. Sootblowers

The sootblower is normally provided as a stand-alone proprietary system.

3.6.1. Modes of Operation

1. An operator-initiated, automatic sootblower sequence incorporating the following features:
   a) Allow the lockout of any sootblower(s) from the normal operating sequence.
   b) Allow the sequence to be held at any point through operator intervention and enable individual sootblowers to operate in the manual or local mode during the hold period.
   c) On reselection of the automatic mode, the sootblower sequence shall continue from where it was interrupted.

2. Manual control of individual sootblowers from the sootblower control panel.
3. Manual control of each sootblower from a pushbutton located at the sootblower.
4. Local manual mode shall take precedence over panel manual mode, which shall take precedence over automatic mode.

3.6.2. Initiation

The initiation of any mode of operation shall be inhibited until the following conditions have been satisfied:

1. The steam supply system has achieved warm-up and all condensate has been removed from the system.
2. Steam pressure has been established.

Irrespective of the mode of control selected, one sootblower shall be in operation at all times.

- Interlocks shall be provided to prevent the start of any single sootblower cycle until all other sootblowers have completed their cycle.
- An emergency stop button shall be provided on the sootblower panel. Initiation of the stop button shall automatically retract any operating retractable sootblower and shut down the system to a safe condition.
- The control systems shall be implemented through the use of a Programmable Electronic System (PES).
  - It shall not be part of the BMS or require the use of a TMR/PLC.
  - The requirements of MP 32-P-07 with respect to PES shall apply.

3.6.3. System Status

The following minimum indications of the system status shall be provided:

1. The control mode selected
2. Automatic sequence in operation
3. The specific individual sootblower that is in operation
4. The direction of travel of the sootblower in operation
5. Steam system warm-up period in progress
6. Specific sootblower(s) that are locked out of operation
7. The open/close position of all actuated supply valves between the plant steam header and the boiler sootblower system

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8. A power-on/healthy indication (driven by the PES)

3.6.4. Alarms

The following are the minimum number of alarms that shall be provided:

1. Elapsed Time Alarm: should a sootblower remain in operation for more than its normal operating time, an alarm shall be generated and all operating retracting sootblowers shall be retracted.
2. Motor Overload Alarms: should the motor current rise to preset fault levels, an alarm shall be generated and all operating retractable sootblowers shall be retracted. Should the current continue to rise, then a second device shall cut off power to the motor and generate a trip alarm.
3. Steam Pressure Alarm:
   a) In the event of low or high steam supply pressure during operation, an alarm shall be generated.
   b) All operating retractable sootblowers shall be retracted and further operation shall be discontinued.
4. Out of Sequence Alarm: if a sootblower fails to commence its cycle, an alarm shall be generated and the sequential controller shall proceed to the next sootblower in the sequence.

3.7. Level Control and Shutdown on the Steam Drum

3.7.1. Preferred Arrangement

The following arrangement offers an optimum combination of safety, reliability and cost:

1. Four level transmitters shall be installed to measure the steam drum water level.
   a) Separate connections are required for each transmitter.
   b) All transmitter taps shall have the same elevation.
2. The transmitters shall be installed at the most stable operating point in the drum.
   a) If this is undetermined, two transmitters shall be located at each end of the drum.
   b) On boiler designs where flue gas flow is along the length of the drum, the transmitters shall be located in the center of the drum.
3. All four transmitters shall be wired to provide a 4-20 ma signal directly to the BMS and the signal shall be connected by an isolated input to the DCS.

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4. A four-position switch shall be provided on the local panel to select any transmitter for blowdown or calibration.

    a) The switch shall be wired directly to the BMS from the output of the BMS to the level control system in the DCS and shall be used to take any one transmitter out of service at any time.

    b) Three transmitters shall be in service at all times.

5. A median select routine shall be used in the BMS to choose the transmitter to be used for high and low shutdown from the three transmitters in service.

    a) This signal is not compensated for the head of steam in the dry leg; therefore, care shall be taken if setting the trip levels with no pressure in the drum.

    b) In this case, the low level trip shall be set higher than the actual trip level anticipated under operating conditions, since the steam head makes the level appear higher than it actually is.

6. A median select routine shall be used in the DCS to select the transmitter used for control and high and low pre-alarms. This signal shall be compensated for head of steam in the dry leg based on steam drum pressure.

7. All devices shall have separate block valves and shall be capable of being calibrated or replaced in service without shutting down the plant or requiring any bypass other than the blowdown switch.

3.7.2. Alternate Arrangement 1

Arrangement 1 is similar to that described in Section 3.7.1 except that two transmitters are used for control and two transmitters for shutdown. The disadvantages of this arrangement are that it is less reliable and requires transmitters to be bypassed for calibration and blowdown. This arrangement has been used before the availability of Programmable Electronic Systems, and situations shall arise where local regulatory authorities prefer this more traditional approach.

1. Two transmitters shall provide the signals for low and high shutdown.

    a) These shall be connected directly to the BMS.

    b) When either transmitter reaches the high or low trip point, the boiler shall be shut down.

2. Two transmitters shall be used for control and pre-alarms.

    a) These shall be connected directly to the DCS. The controlling transmitter shall be selected manually.

    b) If any transmitter goes out of range, the alternate transmitter shall be selected automatically.

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3. All devices shall have separate block valves and shall be capable of being calibrated or replaced in service without shutting down the plant or installing a temporary bypass.

4. A manual spring return timed bypass switch shall be installed at each transmitter to allow blowdown.

3.7.3. Alternate Arrangement 2

Arrangement 2 uses shutdown level switches instead of transmitters for shutdown and is similar in terms of reliability and safety to the preferred arrangement. Since this arrangement has the possible advantage of separating control and shutdown functions, it shall be more acceptable to some local regulatory authorities.

1. Four high and four low switches shall be wired directly to the BMS. The switches shall be probe-type Hydrotect by Schlumberger.

2. A four-position switch shall be provided on the local panel.

   a) This switch shall be wired directly to the BMS and used to take any pair of high and low switches out of service at any time.

   b) Three switch pairs shall be in service at all times.

   c) The purpose of this switch is to select any high/low switch pair for blowdown.

3. Two transmitters shall be used for control and pre-alarms.

   a) These shall be connected directly to the DCS.

   b) The controlling transmitter shall be selected manually.

   c) If any transmitter goes out of range, the alternate transmitter shall be selected automatically.

4. All devices shall have separate block valves and shall be capable of being calibrated or replaced in service without shutting down the plant or installing a temporary bypass.

3.8. Level Gauges on the Steam Drum

3.8.1. General Requirements

1. Gauge glasses, water columns and level indication shall be in accordance with the requirements of ASME SEC I (Section 1 of the ASME Boiler and Pressure Vessel Code).

2. The range of the gauges shall be the same as the transmitters on the steam drum.

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a) The level indicated on the gauge shall correlate with the transmitter level throughout its entire range (control and shutdown).

b) Gauges shall have a minimum visible range of 381 mm (15 in).

3. Conventional gauge glasses shall be provided with illuminators and a sun visor. All trim shall be stainless steel.

4. Gauge glasses shall have separate block valves with a minimum of DN 25 (NPS 1 [NPS = nominal pipe size in inches]) connection and shall also be provided with quick shutoff valves and drains.

3.8.2. Alternative Arrangement 1

1. Two Hydrostep gauges and at least one conventional gauge glass shall be installed.

2. The Hydrostep gauges shall be installed with one at each end of the drum.

3. The conventional gauge glass shall be located adjacent to the control equipment. If control equipment is located at each end of the drum, a gauge glass shall also be located at each end of the drum.

4. The Hydrostep gauge is manufactured by Schlumberger, is based on a series of probes and has a local electronic indication of level through a series of light emitting diodes (LEDs) which show whether a probe is in steam or water.

a) The level indication from both gauges shall be repeated to the local panel.

b) A similar type of LED indication shall be used on the local panel.

3.8.3. Alternate Arrangement 2

1. Two conventional gauge glasses shall be provided.

2. One of the gauge glasses shall be a color port type with a periscope to allow the gauge to be viewed from grade or operating platform.

3. The second glass shall be adjacent to the control transmitters.

3.9. Desuperheater Controls

When a desuperheater is incorporated, provision shall be made to regulate the controlled steam temperature to within 5°C (10°F) of the designated operating point over the full range of load variation specified for the boiler.

- A pressure controller shall be used to regulate the water pressure to a desuperheater spray control valve.

- A temperature indicator controller with a receiver instrument visible from the desuperheater shall be provided to control the desuperheated steam temperature.
  - This indicating temperature control station shall control spray water injection rate.
  - A high temperature alarm on the controlled steam line shall be provided in addition to a local temperature indicator.
- The spray water control valve shall lock in position (drift closed) on air failure and shall be provided with a handwheel.

3.10. Safety Trip Valve

Fuel headers on boilers shall be provided with a safety trip valve located in a fire safe area a minimum of 15 m (50 ft) from the nearest burner.

- The safety trip valve shall comply with the requirements for shutdown valves described in this Practice and shall close on air failure.
- This valve shall be operated through the BMS from the manual emergency shutdown switches located on the local panel, in the control room and a minimum of 15 m (50 ft) from the boiler.
- The emergency manual switches shall also initiate an emergency shutdown of the boiler.

3.11. Annunciation and Event Logging

When possible, all pre-alarms shall be generated in the DCS and the DCS shall log all alarms (shutdown and pre-alarms).

- Pre-alarms on the local panel shall be fed from outputs on the DCS so that the setpoint for a pre-alarm will be set in the DCS and will alarm at the same level, irrespective of where it is displayed.
- When possible, all shutdown alarms shall be generated in the BMS.
  - Shutdown alarms on the local panel shall be fed from outputs on the BMS.
  - The local panel annunciator shall have a first-up facility for all shutdown alarms.
  - The shutdown alarms shall be communicated to the DCS via a serial link.
- The BMS shall have a directly connected printer.
- All significant changes of state, including startup sequences, failures and shutdowns, shall be logged on this printer.

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3.12. Signal Communications

All signals from transmitters and switches in the field shall be hardwired.

- Communication between the DCS control stations and operator consoles shall be by dual redundant data highways.
- Command, inhibit and permissive signals between the modulating control systems in the DCS and the BMS shall be hardwired.
- There shall be a serial link between the BMS/PES and the DCS.
  - Status and individual shutdown alarms shall use this link.
  - It shall not be used for command, inhibit, permissive or control signals.

3.13. Shutdown (Chopper) Valves

This Section refers to those valves that are used to shut down and vent the fuel systems.

- All valves shall meet design requirements and have PN 50 (Class 300) flanges as a minimum.
- All valves shall be ball type and fire safe to API STD 607.
  - Valves shall be resilient seated providing the temperature is less than 205°C (400°F).
  - Valves shall be leak tested to API RP 598 (high and low pressure closure tests).
- Open and closed limit switches shall be provided.
- The nonmagnetic proximity type is preferred.
- All valves (including the valves in the pilot line) shall be diaphragm-actuated, spring return.

3.14. Relief Valves

Relief valves shall be installed on the steam drum and downstream of the superheater. These shall be flanged nozzle pop safety types with adjustable blowdown, lifting gear and test gauge in accordance with ASME SEC I.

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3.15. Power Supplies

3.15.1. Redundant Power Supplies

The preferred power supply arrangement is two dedicated redundant UPSs shared by all boilers in a utility plant.

- The loss of one power supply shall not cause a boiler to trip.
- The DCS systems shall include two separate internal DC power supplies and be capable of operating with the loss of either one.
- Each internal supply shall be connected to a separate UPS supply.
- A standard feature of TMR systems is two separate internal power supplies that will operate independently.
- Each internal supply shall be connected to a separate UPS supply.
- Redundant DC power supplies, along with the appropriate TMR termination modules, shall be used for all field loads directly connected to the TMR.
- Care shall be taken to ensure that this philosophy is carried through to all shutdown inputs (e.g., flame detectors that are not loop powered).
- The backup power supply duration shall be a minimum of 30 minutes.

3.15.2. Dedicated Power Supplies

Boilers shall be provided with dedicated power supplies, if local codes require.

- This is less reliable and shall be more expensive than the redundant power supply arrangement.
- This arrangement shall only be used with approval.

3.16. Panel Construction

All field panels shall be manufactured from stainless steel.

- Panels shall be rated NEMA 4X minimum.
- All switches, lights and instruments shall be suitable for outdoor use and the relevant area classification without the use of additional covers.
  - Where this requirement cannot be complied with, a cover with a clear window shall be provided, if approved.

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  - If a cover is used, it shall not interfere with the operation of the panel and shall be provided with quick release catches.

- A Klaxon and strobe light shall be provided to operate in conjunction with the annunciator.
- The panel supporting structure shall be isolated from the main boiler firing platform structure so that boiler-induced vibrations will not cause damage to the instruments or require regular maintenance. Side and top hoods shall be provided for weather protection.

3.17. Analyzers

- An oxygen analyzer of the zirconium oxide type shall be provided. This shall be used for trimming the airflow (within limits) to control excess air.
- Where variations in the calorific value of the fuel gas are expected, they shall be automatically compensated for by an inferential calorific value based on the online measurement of specific gravity.
- A smoke analyzer (opacity meter) shall be provided on each boiler stack.
- A sulfur dioxide analyzer shall be provided when required by local code.
- A stack gas combustibles analyzer shall be provided.

4. Testing

The entire boiler control system shall be systematically tested during the manufacturing stage and in the field prior to commissioning of the boiler. The boiler supplier shall be responsible for providing a test procedure with adequate notice at each test stage.

Typical tests include:

1. After manufacture and programming, but before shipment to the field, the BMS shall be fully tested for function by simulating all startup and shutdown conditions for the boiler. This shall be done in conjunction with the BMS section of the local panel, flame detection system and the fuel racks.
2. After manufacture and configuration but before shipment to the field, the DCS system shall be fully checked by simulating inputs to the system.
3. All outputs, calculations and control algorithms shall be checked.
4. After shipment to the field and the installation and connection of all field instruments and panels, the entire system shall be checked.
5. A boiler startup shall be simulated and all shutdown devices shall be operated to ensure that they function correctly.

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6. All testing shall be witnessed.

7. Where individual boilers cannot be taken out of service for testing, means shall be provided for online testing of the final control elements and online testing of PES outputs.

Modifications to API RP 556

The instrumentation and control systems shall conform to API RP 556, Sections 4.0 and 5.0, except for the following modifications and additions and those noted elsewhere in this Practice. The paragraph numbers that follow refer to those used in API RP 556.

4.2.1. Addition

Refer to Sections 3.7 and 3.8 of this Practice.

4.3. Addition

For minimum control systems operator interface requirements in the control room and the local panel, see the relevant Sections of this Practice.

- Selection of control modes (auto to manual, local to remote, etc.) shall be bumpless.
- All parts of the control system shall be properly coordinated to permit operation of single and multiple boilers with maximum sensitivity and without the tendency to hunt.
- All components in a given control loop shall act in concert over the total range of the final control element. For example, the combustion air flow transmitters and all associated control components shall continue to have a "live" readout within their individual ranges over the extreme operating range of the final air intake vane actuator or turbine governor, or both.

4.3.1. Addition

Steam pressure in the main header shall be controlled by a plant master pressure controller, which in turn shall control the rate of combustion or heat release of the connected boilers to satisfy total steam demand.

- The controller shall maintain the desired steam pressure within 2 percent of the set point at all loads within the rated capacity of each boiler.
- Means of manually setting and automatically maintaining the relative loading between boilers shall be provided. The relative duty of each boiler may be adjusted via its boiler master controller (ratio bias station).
- In multiple boiler installations, a minimum of one boiler shall be connected to the plant master pressure controller at all times.
  - Other modes of control, which shall be considered to suit operational circumstance, are fuel (usually gas) availability and base loading.

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  - Steam drum pressure control shall also be included for bringing a boiler online.

- For modes of control (other than master pressure control), interlocks shall be provided to ensure that pressure set by the plant master pressure controller is not exceeded. Setpoint runback controls shall be included to ensure that boilers not on plant master pressure control do not exceed a maximum set pressure.

4.3.2. Addition

The controls shall provide for modulation to maintain stability with a continuously fluctuating load demand that increases or decreases at a maximum rate of 20 percent MCR per minute.

- To ensure controllability, the control system shall be capable of a turndown ratio that is one ratio better than the boiler-burner combination selected.

- The controls shall also ensure low-fire start (i.e., 25 percent MCR air flow and the minimum fuel rate necessary to maintain a stable flame on the burners).

4.3.2. User's Choice

Combustion controls for each boiler shall include fuel-flow and air-flow controllers and fuel-air-ratio control.

- The fuel/air ratio shall be controlled to maintain stable and smoke-free combustion conditions within the span of -5 percent and +20 percent. An alarm to indicate excessive fuel air ratio shall be provided.

- The controls shall ensure that the fuel flow follows the air flow on an increasing demand in both automatic and manual modes of control. An alarm shall be provided to alert the operator when an attempt has been made to manually control a fuel valve, but the valve does not operate because of insufficient combustion/air.

- Where a boiler uses combination oil-gas firing, the control shall permit the maximum use of either fuel while maintaining stable firing of the other.

- The gas availability control shall be designed so that a gradual decrease in fuel gas heat input results in a corresponding increase in fuel oil heat input when the gas supply header pressure drops.

  - This shall be a modulating control system operating between selected gas pressure limits.

  - If the gas flame is extinguished, the fuel oil flowrate shall not be decreased automatically on restoration of gas pressure.

  - Low fuel oil flow limits shall be provided to prevent burner operation from becoming unstable when gas is available.

- To maintain the correct combustion fuel-air mixture over the entire burner range, do not burn only gas through one burner throat and only oil through a separate burner throat.

4.3.3.3. User's Choice

The primary flow elements for steam and feedwater shall be austenitic stainless steel flow nozzles.

4.3.3.3. Addition

A three-element feedwater control system shall be furnished with the facility for single element level control during startup.

- The feedwater flow control valve actuator shall be of the diaphragm type.
  - The valve characteristic shall be equal percentage.
  - The valve shall be mounted near grade and shall have an indication of the drum water level located beside it.
  - The valve shall be designed to fail closed and shall lock in last position on air failure.
- The feedwater control valve shall meet a sound specification of less than 85 ±5 dBA at one meter irrespective of the number of feedwater pumps in operation. When used for filling the boiler, the feedwater control valve shall be capable of operating against no load pump pressure and atmospheric pressure downstream.

4.3.4. Addition

Consideration shall be given to the use of conductivity measurement for the automatic adjustment of the blowdown control valve to correct changes in the solids concentration. Any change in the conductivity of the blowdown water causes an appropriate decrease or increase in the rate of continuous blowdown.

4.4. Addition

Transmitters coupled to analog input cards are preferred to field mounted switches for shutdown devices.

See Section 3.7 of this Practice for the preferred method of drum water level shutdowns.

4.4.1. User's Choice

Shutdown alarms shall have a first-up feature. All repeat common alarms (pre-alarm and shutdown) shall have a reflash facility.

The suggested alarms in this Section shall be included in the local panel and the DCS.

4.4.4. Addition

The flame detector shall be proven to be responsive to the type of flame to be detected.

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At least two sensors shall be installed in parallel for each burner. As an alternate, three sensors may be installed per burner if physical space allows.

- Two Detector Operation
  - If feasible and field-proven, each flame detector shall monitor the igniter flame during lightoff and the main burner flame during normal operation.
  - Usually, the dual igniter/main flame arrangement will sense the main flame, provide redundancy and increase the detector signal output.
  - The pilot flame shall be proved if detected by one detector.
  - After proof of main flame by both detectors, loss of flame by one detector on a burner shall sound an alarm.
  - Loss of flame detection by both detectors shall shut that burner down.
- Three Detector Operation
  - Each flame detector shall monitor the igniter flame during lightoff and the main burner flame during normal operation, if feasible.
  - Alternatively, one or two detectors shall be specifically needed for the igniter flame.
  - The pilot flame shall be proved if detected by one detector.
  - The main flame shall be proved if detected by two detectors.
  - Loss of flame by one detector on a burner shall sound an alarm.
  - Loss of flame detection by two detectors shall shut that burner down.

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Appendix: Instrument List

Table A–1: Instrument List

Function	Instrument Type	Location				Notes
		Control Room	Local Panel	Fan Panel	Field	
Boiler emergency shutdown	Pushbutton(s)	Yes	Yes	No	Yes	Field button located 15 m (50 ft) from boiler.
Pilot shutdown	Pushbutton(s)	No	Yes	No	No	Per pilot.
Fuel oil shutdown	Pushbutton(s)	No	Yes	No	No	Per burner.
Fuel gas shutdown	Pushbutton(s)	No	Yes	No	No	Per burner.
Valve status (open and closed). Include all actuated valves forming part of the startup sequence and manual supervisory valves; refer to NFPA 8501 and NFPA 8502.	LED(s)	Yes	Yes	No	No	Include in graphic display of DCS in the main control room. Information is communicated from the BMS to the DCS via the serial link.
Select startup fuel (oil or gas)	Switch	No	Yes			
Fuel gas selected	LED	Yes	Yes			
Fuel oil selected	LED	Yes	Yes			
Starting sequence operation; provide a pushbutton at each stage of the supervised manual lightoff sequence as required by NFPA 8501 and NFPA 8502.	Pushbutton(s)	No	Yes	No	No	Provide status information in the main control room via the serial link.
Start fan(s)	Pushbutton	No	No	Yes		
Stop fan(s)	Pushbutton	No	No	Yes	Yes	Field stop button located beside fan.
Fan(s) running	Green LED	Yes	Yes	No	No	Include in graphic display of DCS in the main control room. Information is

Function	Instrument Type	Location				Notes
		Control Room	Local Panel	Fan Panel	Field	
						communicated from the BMS to the DCS via the serial link.
Air flow controller	Controller	Yes	Yes	No	Indicator	Locate local receiver indicator beside air flow control dampers.
Fuel gas flow controller	Controller	Yes	Yes	No	Indicator	
Fuel oil flow controller	Controller	Yes	Yes	No	Indicator	
Pilot gas pressure	Controller	Yes	Yes	No	Indicator	Locate local receiver indicator beside control valve and a local pressure gauge.
Flame intensity	Indicator	Yes	Yes	No	No	Separate indicator for each flame detector.
Steam drum pressure	Controller	Yes	Yes	No	Indicator	Provide a 150 mm (6 in) pressure gauge visible from the firing platform.
Superheater outlet pressure	Indicator	No	No	No	Yes	Provide a local pressure gauge at each stage. Gauge shall be 150 mm (6 in) and visible from the firing platform.
Boiler feedwater supply pressure	Indicator	Yes	Yes	No	No	Before the economizer.
Boiler feedwater supply pressure	Indicator	Yes	Yes	No	No	After the economizer.
Fuel gas supply pressure	Indicator	Yes	Yes	No	Yes	Locate upstream of control valve. Provide a local pressure gauge.
Fuel oil supply pressure	Indicator	Yes	Yes	No	Yes	Locate upstream of control valve. Provide a local pressure gauge.
Pilot gas supply header pressure	Indicator	Yes	Yes	No	Yes	Locate upstream of control valve. Provide a local pressure gauge.
Fuel gas supply header pressure	Indicator	Yes	Yes	No	Yes	Locate downstream of control valve. Provide a

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Function	Instrument Type	Location				Notes
		Control Room	Local Panel	Fan Panel	Field	
						local pressure gauge.
Fuel oil supply header pressure	Indicator	Yes	Yes	No	Yes	Locate downstream of control valve. Provide a local pressure gauge.
Atomizing steam differential pressure	Controller	Yes	Yes	No	Indicator	
Atomizing steam supply pressure	Gauge	No	No	No	Yes	Locate upstream of control valve. Provide a local pressure gauge.
Atomizing steam at burners	Gauge	No	No	No	Yes	Locate downstream of control valve. Provide a local pressure gauge.
Excess air bias	Manual loader	Yes	No	No	No	-5 to +20 percent.
Boiler drum level	Controller	Yes	Indicator		Indicator	Indicator at local panel shall be based on Hydrostep. Controller in control room. Local indicator to be located beside the boiler feedwater control valve.
Boiler feedwater flow	Controller	Yes	Yes	No	Indicator	Local indicator to be located beside the boiler feedwater control valve.
Boiler steam outlet temperature	Indicator	Yes	Yes	No	No	
Steam temperature inlet to superheater	Indicator	Yes	Yes	No		
Superheater tube skin temperature(s)	Indicator	Yes	No	No	No	Provide a minimum of four points. These shall be switch selectable with a single indicator.
Desuperheater inlet temperature	Indicator	Yes	No	No	Yes	
Final steam control temperature	Controller	Yes	Yes	No	Yes	After superheater/ desuperheater configuration.

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Function	Instrument Type	Location				Notes
		Control Room	Local Panel	Fan Panel	Field	
Furnace pressure (flue gas damper or induced draft fan)	Controller	Yes	Yes	No	Indicator	If required by boiler type. Locate local indicator beside the damper controlling furnace pressure.
Furnace convection section temperature(s)	Indicator	Yes	Yes	No	No	Quantity to suit boiler.
Stack temperature	Indicator	Yes	Yes	No	No	
Stack pressure	Indicator	Yes	Yes	No	No	After economizer.
Furnace pressure	Indicator	Yes	Yes	No	No	Quantity to suit boiler, minimum six for windbox, furnace and breaching pressures.
Steam production flowrate	Indicator	Yes	Yes	No	No	Include a totalizer in the DCS.
Condensate flow to desuperheater	Indicator	Yes	Yes	No	No	Include in three element level control scheme. Provide integrator in the DCS.
Boiler master control	Ratio bias station	Yes	Yes	No	No	
Steam header pressure	Controller	Yes	Indicator	No	No	Controller in the utilities control room. Indicator in the local panel.
Atmospheric vent	Manual loader	Yes	Yes	No	No	
Oxygen content	Analyzer and indicator	Indicator	Indicator	No	Analyzer	Used for oxygen trimming. Local indicator integral with analyzer.
Smoke density	Analyzer	Indicator	Indicator	No	Analyzer	
CO content	Analyzer	Indicator	Indicator	No	Analyzer	
Blowdown conductivity	Analyzer	Indicator	Indicator	No	Analyzer	
Blowdown control valve	Manual loader	Indicator	No	No	No	
Pre-alarms (nonshutdown)	Annunciator	All	All	No	No	

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Function	Instrument Type	Location				Notes
		Control Room	Local Panel	Fan Panel	Field	
in accordance with NFPA						
Shutdown alarms in accordance with NFPA	Annunciator	Common	All	No	No	
Fan system pre-alarms	Annunciator	Common	Common	All	No	Common alarm repeated from fan panel shall have reflash facility.
Fan system shutdown alarms	Annunciator	Common	Common	All	No	
Excess fuel air ratio	Annunciator	Yes	Yes	No	No	See modifications to Paragraph 4.3.2 of API RP 556 (as stated in this Practice).
Fuel limit alarm	Annunciator	Yes	Yes	No	No	
Maintenance bypass alarm	Annunciator	Yes	Yes	No	No	See Section 3.3.1 of this Practice.
Alarms in accordance with API RP 556	Annunciator	Yes	Yes	No	No	
Loss of single flame detector	Annunciator	Yes	Yes	No	No	

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Offshore Pipeline Installation

MP 20-P-04

June 1998

Scope

This Mobil Engineering Practice (MEP) covers basic requirements for the installation, inspection and testing of submarine pipelines and risers. Pipeline and riser design, materials, weight coating, corrosion protection coating and cathodic protection are covered in other Mobil documents.

Version 0

Table of Contents

Scope **1**

1. References **6**

1.1. MEPS–Mobil Engineering Practices 6

1.2. Mobil Data Sheets 6

1.3. Mobil Tutorials 7

1.4. API–American Petroleum Institute 7

1.5. ASME– American Society of Mechanical Engineers 7

1.6. ASNT–American Society for Nondestructive Testing 8

1.7. AWS–American Welding Society 8

1.8. BSI–British Standards Institute 8

1.9. CFR–U.S. Code of Federal Regulations 8

1.10. ISO–International Organization for Standardization 8

1.11. SIS–Swedish Standards Institute 8

2. General **9**

3. Design Data **9**

4. Installation Equipment **9**

5. Construction Engineering and Procedures **10**

5.1. Engineering 10

5.2. Procedures 12

6. Prelay Survey **13**

6.1. Prelay Activities 13

6.2. Scope Considerations 14

6.3. Minimum Coverage 14

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7. Crossings 14

8. Pipe Lay 15

8.1. Transportation 15

8.2. Alignment 15

8.3. Lay Operations 16

8.4. Pipelay Equipment Checks 16

8.5. Tension Control 17

8.6. Monitoring and Control of Pipe Configuration 17

8.7. Strip Chart Records 18

8.8. Abandonment and Recovery of Pipeline 18

8.9. Wet and Dry Buckle Repair 19

8.10. Diving 20

8.11. Pipeline Initiation and Termination 20

8.12. Pipe Laying Records 20

9. Field Joint Welding 21

9.1. General 21

9.2. Equipment 21

9.3. Welding Consumables 22

9.4. Welding Procedure Specification (WPS) 23

9.5. Welding Procedure Qualification (WPQ) 24

9.6. Qualification of Welders 25

9.7. Production Welding 26

9.8. Repair Welding 28

9.9. Non-Destructive Testing 30

9.10. Field Joint Coating 35

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10. Anodes 40

10.1. Semi-Cylindrical Anodes 40

10.2. Anode Protection 41

11. Protection Coatings—Inspection and Repair 41

11.1. Repair Guidelines 42

11.2. Repair of Corrosion Protection Coating 42

12. Risers 42

12.1. Installation 42

12.2. Testing 43

13. Shore Approach 43

13.1. Included Activities 43

13.2. Welding and Coating Requirements 44

13.3. Documentation 44

13.4. Trenching and Burial 44

14. Post Lay Survey 44

14.1. Accuracy 45

14.2. Survey Vessel 45

14.3. Documentation Requirements 45

15. Maximum Span Lengths and Span Correction 45

16. Pipeline Stabilization and Burial 46

16.1. Procedures 46

16.2. Rock Dumping 46

16.3. Inspection/Testing 46

17. Hydrostatic Testing 47

17.1. Material and Equipment 47

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17.2. Filling the Pipeline 48
17.3. Restriction Test 49
17.4. Hydrostatic Pressure Test 49
17.5. Test Records 50
17.6. Repair of Defects 50
17.7. Sealing the Pipeline 51

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1. References

The following publications form a part of this Practice. Unless otherwise specified herein, use the latest edition.

1.1. MEPS–Mobil Engineering Practices

MP 20-P-01	Offshore Pipeline Design
MP 20-P-02	Line Pipe and Bend Material
MP 20-P-03	Offshore Pipeline Weight Coating
MP 20-P-14	Pipeline Corrosion Protection
MP 55-P-19	Materials and Corrosion for Sour Service

1.2. Mobil Data Sheets

Mobil Data Sheets	Mobil Data Sheet Home Page
T2001C01	Offshore Pipeline Design - Pipeline Design - Customary Units
T2001C02	Offshore Pipeline Design - Pipeline Route Environment Data - Customary Units
T2001M02	Offshore Pipeline Design - Pipeline Route Environment Data - Metric Units
T2001C03	Offshore Pipeline Design - Pipeline Fluid Property Characteristics - Customary Units
T2001M03	Offshore Pipeline Design - Pipeline Fluid Property Characteristics - Metric Units
T2001C04	Offshore Pipeline Design - Pipeline Weight Coating Design - Customary Units
T2001M04	Offshore Pipeline Design - Pipeline Weight Coating Design - Metric Units
T2001C05	Offshore Pipeline Design - Corrosion Coating and Cathodic Protection Data - Customary Units
T2001M05	Offshore Pipeline Design - Corrosion Coating and Cathodic Protection Data - Metric Units
D2001C01	Offshore Pipeline Design - Documentation Requirements Sheet
T2004C01	Offshore Pipeline Installation - Pipe Design Details - Customary Units

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T2004M01	Offshore Pipeline Installation - Pipe Design Details - Metric Units
T2004C02	Offshore Pipeline Installation - Pipeline Route Environment Data - Customary Units
T2004M02	Offshore Pipeline Installation - Pipeline Route Environment Data - Metric Units
T2004C03	Offshore Pipeline Installation - Vessels - Customary Units
T2004M03	Offshore Pipeline Installation - Vessels - Metric Units
T2004C04	Offshore Pipeline Installation - Welding Procedures Analysis - Customary Units
T2004M04	Offshore Pipeline Installation - Welding Procedures Analysis - Metric Units
T2004C05	Offshore Pipeline Installation - Hydrotesting Offshore Pipelines and Risers - Customary Units
T2004M05	Offshore Pipeline Installation - Hydrotesting Offshore Pipelines and Risers - Metric Units
D2004C01	Offshore Pipeline Installation - Documentation Requirements Sheet

1.3. Mobil Tutorials

EPT 10-T-05	Offshore Tanker Loading Systems
EPT 10-T-07	Submarine Pipelines
EPT 10-T-08	Engineering Checklist for the Design, Manufacture and Construction of Submarine Pipelines

1.4. API–American Petroleum Institute

API SPEC 5L	Specification for Line Pipe Forty-First Edition
API STD 1104	Welding of Pipelines and Related Facilities Eighteenth Edition

1.5. ASME–American Society of Mechanical Engineers

ASME B31.8	Gas Transmission and Distribution Piping Systems

1.6. ASNT–American Society for Nondestructive Testing

ASNT SNT-TC-1A	Recommended Practice December 1992 Edition

1.7. AWS–American Welding Society

AWS A5.1	Specification for Carbon Steel Electrodes for Shielded Metal Arc Welding
AWS A5.5	Specification for Low-Alloy Steel Electrodes for Shielded Metal Arc Welding

1.8. BSI–British Standards Institute

BS 4515	Specification for Welding of Steel Pipelines on Land and Offshore

1.9. CFR–U.S. Code of Federal Regulations

49 CFR 192	Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards
49 CFR 195	Transportation of Hazardous Liquids by Pipeline

1.10. ISO–International Organization for Standardization

ISO 2504	Radiography of Welds and Viewing Conditions for Films - Utilization of Recommended Patterns of Image Quality Indicators (I.Q.I.) First Edition

1.11. SIS–Swedish Standards Institute

SS 05 59 00	Pictorial Surface Preparation Standards for Painting Steel Surfaces

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2. General

The installation, inspection and testing of submarine pipelines and risers shall be in accordance with requirements of this MEP, unless superceded by more stringent local regulations.

The requirements of this Practice apply to all methods of submarine pipeline installation, including reel, S-type, J-type lay and bottom pull and tow.

3. Design Data

Pipeline design data are given on the Mobil Data Sheets for this MEP. Environmental data are given to the contractor for information only. The contractor shall obtain any verification or additional data necessary to perform installation engineering and install the pipeline(s).

4. Installation Equipment

The contractor shall provide the number, type and capacity of equipment sufficient to install the pipeline(s) in a safe and expedient manner.

- A list of equipment shall be supplied in accordance with the Mobil Data Sheets for this MEP at the time of bidding.
- The contractor shall demonstrate in the bid the adequacy of the equipment based on the preliminary engineering analysis. Engineering shall take into account physical conditions, including water depth, bottom soil properties and maximum environmental conditions anticipated during installation. (Refer to the Mobil Data Sheets for this MEP.) Pipeline stresses during installation and testing shall not exceed those given in Section 5.1.3 of this Practice.
- The contractor shall clearly state all environmental criteria and stresses used in the engineering. This shall include safety factors for equipment capacity and pipeline stresses.
- Following completion of detailed installation engineering, the contractor shall review all these safety factors and demonstrate their adequacy. Should any safety factor(s) prove to be inadequate, the contractor shall upgrade equipment as necessary.
- The contractor shall ensure that all equipment proposed in the project is adequate for the use intended and will meet or exceed any and all applicable governmental, industry, environmental, safety and health standards and regulations. It is the contractor's responsibility to determine existing regulatory requirements and ensure compliance.

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- Mobil reserves the right to audit all marine vessels and other construction equipment proposed for use by the contractor. Any equipment failing to comply with either the job specifications or environmental or safety requirements, as determined by Mobil, shall be replaced or modified by the contractor prior to use.

5. Construction Engineering and Procedures

5.1. Engineering

Engineering shall demonstrate the feasibility, adequacy and safety of the intended installation methods. It shall include the preparation of the following:

- Procedures
- Manuals
- Calculations
- Descriptions and drawings

5.1.1. Covered Activities

The following activities (where applicable) shall be covered:

1. Survey and position fixing (including subsea positioning)
2. Seabed preparation
3. Pipeline crossing preparation and completion
4. Storage, handling and transportation of materials supplied by Mobil and the contractor
5. Pipe tracking
6. Pipelay (including startup, laydown, temporary protection of existing pipelines/cables and temporary installation aids)
7. Pipelay over crossings
8. Pipelay abandonment/recovery
9. Pipe welding (automatic and/or manual), including weld repair
10. Welder/welding machine operator qualification
11. Radiography
12. Radiographer qualification

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13. Ultrasonic examination
14. Field joint coating and protection (FBE)
15. FBE coating repair
16. Concrete coating repair
17. Span correction
18. Trenching
19. Rock dumping
20. Flooding, cleaning and gauging
21. Hydrostatic testing
22. Anchor handling and anchor patterns (including layaway pipeline/crossings and laydown)
23. Anchoring-up at any location (e.g., commencement of operations)
24. Dynamic positioning
25. Installation of mechanical subsea connection tools
26. Hyperbaric welding (including welder qualification)
27. Hyperbaric NDT (including tester qualification)
28. Spoolpiece installation
29. Diving operations
30. ROV operations
31. Contingency operations
    a) Wet/dry pipeline buckle
    b) Incorrect positioning of line
    c) Anchor wire failure or jettisoning
    d) Pennant failure and buoy loss
    e) Damage repair to existing pipelines/cables

5.1.2. Analysis and Calculations

As a minimum, analyses and calculations for the following activities shall be prepared by the contractor:

1. Route survey to determine the requirement (if any) for seabed preparation

2. Pipelay static and dynamic stresses to determine operating pipelay configurations, pipe stresses and lay tensions for all pipelay conditions (including abandonment/recovery and startup/laydown)
3. Pipeline trenching
4. Allowable span
5. Rock dump installation
6. For the bottom pull method: pull forces, buoyancy, anchor forces, equipment capacity and safety factors
7. For the tow method: pull, buoyancy, alignment and final positioning forces, equipment capacity and safety factors

5.1.3. Stresses and Design Formulae

Allowable stresses and design formulae for installation shall be in accordance with the equations and limits given in Tables 1 and 2 of MP 20-P-01.

5.2. Procedures

The contractor shall develop all procedures required for the installation, inspection and testing of the pipeline system.

The contractor shall ensure that no damage is done to existing pipelines and cables by submitting and following fully developed installation procedures and installing temporary protection where necessary. Specific anchor patterns and placement procedures shall be developed.

5.2.1. Installation Manuals

The contractor shall prepare and submit installation manuals to cover all aspects of the installation. These manuals shall incorporate all engineering calculations and procedures required to define the proposed method of installation and to demonstrate compliance.

The contractor shall prepare and submit a full index of the installation manuals for Mobil review and approval.

The manuals shall include the following elements:

1. Quality plan
2. Diving manuals
3. Safety manuals
4. Document and report formats

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5. Record and inspection forms
6. Calibration procedures and certificates
7. Equipment, rigging and material certificates
8. Final documentation formats

5.2.1.1. Individualized Installation Manuals

Individual Installation Manuals shall be prepared for the following, as applicable:

1. Pre-survey
2. Shore approach preparation and landline installation
3. Pipelay
4. Assemblies installation and tie-in
5. Post trenching and rock dump
6. Cleaning, gauging and hydrotest
7. Precommissioning
8. Shore makeup yard and facilities for bottom-pull and tow methods

6. Prelay Survey

6.1. Prelay Activities

The following prelay survey activities shall be undertaken:

1. A bathymetric and side-scan sonar survey shall be performed prior to commencing pipelay.
2. Contour plans and longitudinal sections shall be prepared (at scales to be approved by Mobil) displaying all pertinent details of the survey and submitted for Mobil review. They shall include the obstructions, pipelines, cables or other seabed features within the pipelay corridor.
3. The extent of trenching and rock dumping shall be determined, including the design of trenching profiles, and submitted for Mobil approval.
4. Seabed preparation requirements shall be analyzed and determined at locations where pipeline spanning may cause excessive stresses or critical spans.

5. The final pipeline route within the specified corridor shall be determined, including preparation of route drawings and submitted for Mobil approval.

6.2. Scope Considerations

The scope of the prelay survey shall be determined by specific job site conditions. Various factors shall affect the extent of prelay survey required along the proposed pipeline route. These include:

- Sea floor conditions
- Existing obstructions (such as foreign pipelines and structures)
- Archeological features
- Government regulations
- Lay techniques
- Anchor patterns

6.3. Minimum Coverage

As a minimum, the survey shall cover the proposed centerline of the pipeline. The contractor shall perform a prelay survey sufficient to ensure that the proposed pipeline will not be damaged because of existing seafloor conditions and, conversely, that the pipelay operations do not damage any existing features in the lay corridor.

7. Crossings

The following activities shall be undertaken:

1. A detailed survey of the crossing location shall be performed comprised of a bathymetric and side-scan sonar survey, a sub-bottom profiling video survey and the procurement of soil samples.
2. Contour plans and longitudinal sections shall be prepared, at scales to be approved by Mobil, displaying all pertinent data. These shall include the location of pipelines to be crossed, depth of burial/degree of exposure, the condition of exposed pipeline and any obstructions in the vicinity of the proposed crossing location.
3. Details of crossing design shall be finalized, based on detailed survey results and calculated bearing pressure (including design of gravel and rock layers in rock dump) and submitted for Mobil approval.
4. Obstacles shall be removed from the vicinity of crossings and the line to be crossed shall be lowered if required.

5. After their installation, a survey of the installed mattresses shall be performed and "as-installed" drawings submitted for Mobil approval. The separation between pipelines shall be a minimum of 0.5 m (1.6 ft).

8. Pipe Lay

8.1. Transportation

- Mobil-furnished line pipe and materials shall be released to the contractor at designated locations in accordance with the schedules given in the job specifications.
- Unless otherwise specified by Mobil, the installation contractor shall receive, load out and transport coated line pipe and all other Mobil-furnished material to the contractors fabrication and installation site in accordance with Section 8 of MP 20-P-03, MP 20-P-14 and the job specifications.
- The contractor shall assume responsibility and custody for all Mobil-furnished materials and shall develop and maintain an inventory and tracking system for these items.
- On job completion, the contractor shall load out and transport remaining line pipe and other Mobil-furnished material to a site specified in writing by Mobil.

8.2. Alignment

- The final on-bottom position of the pipeline shall be located within ±10 m (33 ft) of the approved route centerline.
- The pipeline shall be laid along the predetermined route (in accordance with the Mobil Data Sheets for this MEP) except in the vicinity of the platform approaches and crossings. There, the on-bottom placement of the pipeline shall have a nominal spacing of 90 m (300 ft) from other objects and shall not be closer than 30 m (100 ft) to any adjacent pipeline. Separation between a pipeline and a platform to which the pipeline does not have a connection is 90 m (300 ft) minimum.
- The minimum on-bottom radius shall be determined from Section 5.1.3 of this Practice.
- If the sea floor is too congested to adhere to these requirements, Mobil shall be advised in writing and a proposed pipeline alignment shall be presented to Mobil for approval.

8.2.1. Shallow Water Pipelines

- For shallow water pipelines, the contractor shall install and maintain lighted buoys marking the pipeline alignment at intervals of 305 m (1000 ft) or less.
- Coordinates locating each buoy to within a 3 m (10 ft) radius circle shall be provided to Mobil by the contractor.
- The contractor shall install and maintain buoys to locate the exact positions of all existing pipelines, cables, obstructions or obstacles within 305 m (1000 ft) in any direction of the pipeline right-of-way and other activity areas.
- All information obtained by the contractor on the location of the various obstructions shall be made available to Mobil.
- In lieu of buoys, the contractor may use on-board real time positioning/navigation systems, subject to Mobil approval. If used, such systems shall be operational during the entire installation period.

8.3. Lay Operations

The contractor shall perform the following as applicable:

1. Provide temporary protection, as approved by Mobil, to existing pipelines and structures at startup, during lay and at lay down.
2. Identify and remove obstructions within the pipelay corridor. Seabed preparation may be required, such as boulder removal and sand wave sweep.

8.4. Pipelay Equipment Checks

The contractor shall demonstrate to the satisfaction of Mobil that all equipment, including associated instrumentation and controls on the lay vessel, are of a proven design, in good condition and in full working order. The equipment capabilities shall be demonstrated prior to leaving base and at other such times as required by Mobil.

- The contractor shall demonstrate the accuracy of tensioner and constant tension winch load cells prior to lay. The tension control systems shall be shown to be accurate, efficient and reliable.
- Prior to start of pipelaying, the contractor shall check the height, location and condition of each roller support on the pipelay vessel for adherence to drawings and installation procedures.
- Rollers shall be soft-faced with molded polypropylene or similar material. Worn rollers and tensioner shoes shall be replaced.

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  - The rollers on the stinger shall be inspected prior to the start of the pipe lay and at regular intervals thereafter. No additional inspections may be required if the job is short in duration; e.g., one week. The inspection may be conducted by ROV (Remote Operated Vehicle) or by air divers.
  - Deepwater stingers, which tend to be exposed to high environmental loadings, shall be inspected regularly.

- Prior to the start of pipelay, the contractor shall check and demonstrate that the tensioners and roller supports are precisely aligned on the centerline of the pipe ramp.
- The contractor shall demonstrate the operability of the pipelay stinger prior to the commencement of pipelay. This shall include testing loadcells, cameras and other monitoring equipment.

8.5. Tension Control

The force applied by the pipe tensioning equipment for control of the suspended pipe configuration shall satisfy the following requirements:

- The lowest level of tension in dynamic conditions, including environmental loading on the suspended pipe length, shall be sufficient to keep the pipe stresses within limits prescribed in Section 5.1.3 of this Practice.
- The tensioner squeeze pressure on the pipe shall be kept below a level where the pipe coating or anodes may be damaged.

Prior to commencement of the pipelaying, the contractor shall provide Mobil with a schedule of proposed tensioner settings for application along the pipeline route.

8.6. Monitoring and Control of Pipe Configuration

- The pipe tension, stinger depth and angle, pipe departure angle, maximum sagbend and overbend stresses and the water depth shall be continuously monitored.
- The contractor shall propose a procedure to determine the actual suspended pipe configuration and location of the touchdown point. The determination shall consist of graphs or tables prepared specifically for the pipeline and shall include the following:
  - Effect of pipe tension and tension variation
  - Effect of variation in submerged pipe weight including wet buckle
  - Effect of current induced drag on the suspended pipeline for any direction of current
  - Effect of changes in lay vessel attitude orientation and position
  - Abandonment and recovery of pipe
  - The effect of sea state

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- The pipelay operation shall be monitored by ROV a minimum of twice per day, depending on prevailing weather conditions. At critical locations, continuous monitoring by ROV may be required.

8.7. Strip Chart Records

- The contractor shall maintain a continuous paper strip chart record of the tension applied to the pipe at all times during pipelaying abandonment and recovery operations.
- The strip chart record shall be adequately marked with the time and date at periodic intervals and indicate the operation being carried out.
- The strip chart shall record the tension applied to the pipe by each of the tensioning devices and the tension in the cable shall be used to tension the pipe during abandonment and recovery operation.
- Numerical tension values shall be recorded on the strip chart every hour.

8.8. Abandonment and Recovery of Pipeline

The contractor shall convey the limiting sea state and operational conditions at which pipeline abandonment should commence as well as the elapsed time required to prepare the pipeline for abandonment.

- The contractor shall monitor deteriorating weather conditions and increasing sea states when operating conditions may exceed the operational capabilities of the lay operation.
- The contractor shall initiate procedures in time to complete abandonment before the sea state reaches the limiting conditions for safety of the pipeline.
- The operating sea state limitation for a lay vessel may not be representative of the operating capabilities of the support vessels. For example, third generation North Sea lay vessels can lay pipe in sea states in which the anchor handling tugs and pipe haul vessels cannot operate.

8.8.1. Required Equipment

The contractor shall ensure that the pipelaying vessel is equipped to carry out a pipeline abandonment and recovery procedure. The minimum equipment that shall be carried in readiness is:

- Laydown winch
- Sufficient cable length
- Abandonment/recovery heads

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Instrumentation for monitoring the A/R winch tensions during abandonment and recovery operations shall be provided.

8.8.2. Calculations

- The contractor shall prepare abandonment/recovery calculations that determine stress levels in the pipe on the barge, stinger and sagbend; the reactions on the barge and stinger rollers; and the forces in the abandonment/recovery cable.
- Abandonment/recovery calculations shall be performed for the most critical water depth for each different pipe diameter/wall thickness/concrete combination.
- The calculations shall indicate barge and stinger configuration, roller heights, pipe profiles and the expected pipe tension for all stages of the abandonment/recovery operations.
- All results shall be tabulated and presented in graphic form for ease of use by field personnel and their subsequent usage shall become an integral part of the approved procedures.
- Stresses during abandonment and recovery shall comply with Section 5.1.3 of this Practice.

8.8.3. Heads

- Any pipe end lowered in the water shall have abandonment/recovery heads.
- The installation and removal of abandonment/recovery heads shall be performed by the contractor as part of the normal pipelaying operation. Abandonment/recovery heads shall always be on board the pipe lay barge and kept in ready status.
- Abandonment/recovery heads shall be designed and fabricated by the contractor and be subject to Mobil approval.
- The heads shall have all necessary contingency facilities required to flood and dewater the pipeline. These facilities shall be protected from damage by a protective cage or equivalent.
- In addition, the heads shall be equipped with suitable Mobil-approved marker systems to facilitate their relocation.

8.9. Wet and Dry Buckle Repair

Wet or dry repair shall follow approved procedures. The contractor shall make all provisions to repair a pipeline in case of buckling by installing dewatering pigs, valves in abandonment/recovery heads, etc. as required.

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All buckles shall be repaired as soon as they are discovered, unless otherwise agreed by Mobil.

8.10. Diving

It shall be the sole responsibility of the contractor to ensure that all diving activities are performed in accordance with statutory diving regulations.

8.11. Pipeline Initiation and Termination

At commencement and termination of laying, the contractor shall be required to position the end of the pipeline within the target areas as shown on the contract drawings. On completion of pipe lay down, the contractor shall accurately measure the position of the pipe end. The method for taking these measurements shall be reviewed and approved by Mobil prior to its use.

1. The contractor shall move or adjust the length of the pipeline if the target area is missed during pipeline initiation and termination operations. The contractor's proposed procedure for moving or length adjustment shall be reviewed and approved by Mobil prior to commencement.

2. Existing structures shall not be used for any purposes during pipeline initiation and termination operations other than as specifically permitted by Mobil.

3. During initiation and termination activities, the contractor shall use cables that do not twist when tensioned. Alternatively, swivel connectors shall be used to prevent the transmission of cable twist to the pipe.

4. The holding power of the deadman anchor or pile startup system shall be proved by load testing to 1.5 times the maximum predicted load, holding for 30 minutes. The contractor shall be responsible for clearing the seabed of deadman anchor or pile startup system.

8.12. Pipe Laying Records

- At all times during pipelay operations, the contractor shall keep accurate pipe laying records. These records shall contain the pipe as-laid sequential number with pipe description data that include the following:
  - Pipe identification number
  - Length
  - Wall thickness
  - Negative buoyancy
  - Whether an anode is fitted

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  - Any other information required by Mobil

- The records shall be kept in a neat and orderly manner on recording forms previously approved by Mobil as part of the pipeline installation procedures. At the end of each day, the records, including the total length and number of pipes laid, shall be tallied and two copies supplied to Mobil.

- The sequential pipe number, referring to the pipe and adjacent field joint, shall be clearly painted in white on both sides of each pipe near the field joint. The paint shall be suitable for long term immersion in sea water. The digits shall be a minimum of 150 mm (6 in) high.

9. Field Joint Welding

9.1. General

- All welding and weld inspection shall meet the requirements of API STD 1104 and this Practice.

- Prior to production welding of any pipe or piping component covered by this Practice, the selected type of welding equipment and welding procedure shall be established and qualified. The Welding Procedure Specification (WPS) shall be tested, qualified and documented by the contractor and be witnessed and approved by Mobil.

- Each welder or welding operator shall be qualified for the established production welding procedure before performing any production welding on pipe or piping components installed in accordance with this Practice.

- Welding procedure qualification tests shall be carried out with the same or equivalent equipment to be used during installation. Such tests shall be performed in the place designated on the project pipe by the contractor and agreed on by Mobil. They shall be conducted under conditions representative of installation.

- The qualified and approved welding procedure specification, together with certified results of welding procedures and the welder qualification tests, shall be on file at the work site and available to Mobil at all times. Work not welded in accordance with the approved WPS and/or by qualified welders shall be rejected.

9.2. Equipment

- All welding shall be performed using reliable equipment suitable for the work being done.

- The contractor shall establish a procedure to check and demonstrate to Mobil that all welding machines are properly grounded to avoid the occurrence of stray arcing.

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- The contractor shall provide ground clamps of an approved design and employ only insulated electrode holders and/or leads.
- All welding equipment shall be of the same type used in the welding procedure qualification.

9.3. Welding Consumables

Welding consumables shall be suitable for the intended application and shall produce a weld with the required properties, soundness and corrosion resistance in the finally installed conditions. Welding consumables shall conform to the requirements of the applicable American Welding Society (AWS) specification.

The chemical composition of the weld deposit shall be compatible with the base metal to prevent general and localized corrosion. Content of alloying elements shall be kept at a safe level consistent with documented experience. Possible precipitation effects due to intended heat treatment and hydrogen embrittlement shall be considered.

- Weld metal shall be noble to pipe base metal.
- Mechanical properties of weld metal shall meet base material requirements. Excessively overmatching yield and tensile strength shall be avoided; however, the yield strength of the weld metal shall be greater than the actual yield strength of the base metal.
- The possibility of impairment of tensile and toughness properties caused by post-weld heat treatment shall be considered.
- Welding consumables shall be specified by brand name as well as by the AWS specification.

9.3.1. Handling and Storage

Welding consumables shall be handled in a manner that avoids contamination, moisture pickup and rusting. They shall be stored under dry conditions. Welding consumables shall be protected from all forms of deterioration prior to actual use. Those showing any sign of damage or deterioration shall not be used and shall be promptly removed from the work site.

9.3.2. Electrodes

- All coated welding electrodes for manual welding shall be kept in hermetically sealed containers and stored in accordance with the manufacturer's recommendation. They shall be handled in a manner that ensures no mechanical or physical damage is caused to the coatings.
- Once the sealed containers are opened:
  - Electrodes with low hydrogen covering conforming to AWS A5.1 classification E60XX and E70XX shall be dried in an electrode drier

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for at least two hours at temperatures between 232°C and 260°C (450°F and 500°F).

- Low hydrogen electrodes conforming to AWS A5.5 classification E70XX- X and above shall be dried in an electrode drier for at least one hour at temperatures between 370°C and 426°C (700°F and 800°F).
- The electrodes shall be stored in an electrode holding oven at a minimum temperature of 149°C (300°F) immediately after their removal from the drying ovens.
- The welder shall remove no more electrodes from the holding oven than can be used in two hours.
- Once removed from the holding ovens, the electrodes shall be immediately placed into a portable heated quiver or hot box maintained at 102°C (215°F).
- Electrodes remaining unused three hours after their removal from the holding oven shall be discarded unless returned to the drying oven, reheated for two hours and then replaced in the holding oven.
- Electrodes shall not be re-dried more than three times and shall be discarded if not consumed after the third redry.

- Electrodes that have become wet shall not be used and shall be removed from the work site.

9.4. Welding Procedure Specification (WPS)

A WPS shall be developed by the contractor for each welding procedure and each repair welding procedure that will be used under the contract. Each WPS shall:

- Be based on good industry Practice
- Be appropriate for production welding for this particular project
- Be supported by such factors as metallurgical/welding judgment, experience, research and trials
- Incorporate the constraints stated by Mobil

The contractor shall submit the completed WPSs to Mobil for approval, along with the documentation used in developing them. After approval by Mobil, the WPSs can be submitted for procedure qualification testing.

9.4.1. Minimum Requirements

All parts of the WPS are considered essential and shall be treated as essential variables as defined by API STD 1104.

As a minimum, each WPS shall contain the information required by API STD 1104 plus the following:

1. Method of preheat.
2. Maximum and minimum preheat temperature.
3. Minimum and maximum interpass temperature.
4. A "high hardness" weld procedure by depositing all passes within 11°C (20°F) of the minimum temperature specified in the proposed WPS.
5. A "low Charpy" weld produced by depositing all passes within 11°C (20°F) of the maximum temperature specified in the proposed WPS.
6. Diagram showing bevel, dimensions and tolerances.
7. Diagram showing bead sequencing with each bead numbered.
8. Minimum number of welders/operators for each pass.
9. Maximum permitted time lapse between root pass and second pass and between second pass and third pass.
10. Type of lineup clamp.
11. When permissible to remove lineup clamp.
12. Welding consumable size, specification and brand name for each pass. Only one choice is permissible.
13. For each pass, ranges for heat input, amperage, voltage, speed of travel, electrode wire speed, gas flow rate, gas content, etc. (The instrumentation requirements for recording welding parameters by the contractor shall be clearly stated.)
14. Electrode offset and angle for SAW welding.
15. For WPSs Gas Metal Arc Welding (GMAW), oscillation width and frequency, wire feed, sidewall dwell time, pulsing frequency and parameters.

9.5. Welding Procedure Qualification (WPQ)

- Procedure qualification tests shall be made between line pipe pup pieces of significant length to simulate field conditions. The pipe and heat number of the test pieces and all welding parameters shall be recorded. Test welds shall be made using the same or equivalent equipment used under normal working conditions.
- Line pipe material shall be provided by Mobil. The contractor shall provide all necessary equipment, consumables and personnel.
- The welding procedure qualification shall be witnessed by Mobil. Mobil shall be notified a minimum of 14 days prior to its commencement.

- Procedure testing shall be accomplished in an independent third party laboratory, acceptable to both Mobil and the contractor.

9.5.1. Test Failures

- Each test weld shall be non-destructively inspected in accordance with this Practice. Should the soundness of the test weld fail to meet the acceptance criteria, the weld shall not be submitted for mechanical testing.
- Failures due to lack of fusion or due to cracking shall be investigated and explained to the satisfaction of Mobil. The WPS shall then be changed to eliminate the problems before a new qualification test weld is made.

9.5.2. Specimen Requirements

Test specimen requirements and acceptance criteria for welding procedure qualification shall be in accordance with API STD 1104 with the following exception: pipe diameters 114 mm (4.5 in) OD and less shall require two tensile strength tests and the additional requirements given on the Mobil Data Sheets for this MEP. Failure shall require a change in the WPS unless a reason apart from the WPS is accepted by Mobil.

9.5.3. Hyperbaric Weld WPS

Welding procedure qualification for hyperbaric welding shall be conducted in a pressure chamber using the equipment, gas composition and gas pressure that accurately simulates both the equipment to be used and the anticipated conditions during the actual tie-in.

9.5.4. Consumables

Welding consumables used for the procedure qualifications and production welds shall be from the same batch. The contractor shall ensure that sufficient welding consumables from a single batch are available for both the welding procedure qualification and for production welding.

9.6. Qualification of Welders

- All welders and welding operators shall be qualified prior to the start of production by making at least a one-half circumference test buttweld for pipe 356 mm (14 in) OD and greater, or a full weld for pipe 324 mm (12.75 in) OD or smaller, using the qualified welding procedures.
- Repair welders shall be qualified for weld repairs using repair procedures.
- The test welds shall be made with the pipe in the same position as found in production welding.

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- The qualification test shall preferably be carried out on the barge where the installation welding is to take place or under similar conditions.
- The same or equipment similar to that specified for production welding shall be used.
- Each welder qualified for barge welding shall carry an I.D. card stating the welding procedure for which the welder is qualified.

9.6.1. Examination of Test Welds

Each test weld section shall be subjected to visual and non-destructive inspection in accordance with the requirements of this Practice. Mechanical testing shall comply with the requirements of API STD 1104.

9.6.2. Requalification

Requalification of welders and welding operators is required if any change is made to the welding procedure that necessitates its requalification.

After qualification for the project work, approval is valid if the following condition is obtained and can be documented: the welding operator or the welder has carried out qualified work with acceptable welding performance and with no interruption longer than three months.

9.7. Production Welding

- All welding equipment shall be suitable for production welding and capable of producing welds of the specified quality.
- All equipment shall be maintained in good working order and any unsuitable equipment shall be replaced immediately.
- All welding shall be performed by qualified welders. They shall use qualified welding procedures and welding consumables, fluxes and gases properly identifiable and accepted within the contractor's QA/QC receipt control.

9.7.1. End Preparation

Pipe lengths shall be supplied with the standard API SPEC 5L, 30 degree bevel configuration, unless otherwise specified on the Mobil Data Sheets for this MEP. For pipe-to-pipe welds where wall thickness changes are involved, the joint design shall be approved by Mobil. The taper shall be 1:4 between different wall thicknesses. Pipe bevels shall be checked by means of bevel gauges at regular intervals to ensure uniformity in bevel profiles.

9.7.2. End Inspection

A visual inspection of the pipe ends, up to a distance of 50 mm (2 in) from the ends, shall be carried out. Any pipe bevel showing harmful effects or evidence of end area lamination exceeding the acceptance criteria in API

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SPEC 5L, shall be cut back until the defect is removed and then rebevelled. After rebevelling and removing 19 mm ($^3/_4$ in) or more from the pipe, the pipe end shall be ultrasonically inspected using an approved procedure.

9.7.3. End Cleaning

All bevels shall be cleaned by power tools to a bright finish prior to lining up the pipe.

9.7.4. Identification and Interior Cleaning

- All welds shall be identified according to the sequential field joint number painted on the pipe coating adjacent to the field joint.
- Prior to pipe alignment, but after end beveling, the inside of each pipe shall be cleaned to remove all debris and loose material.
- Each joint shall be swabbed immediately prior to aligning with the pipeline to remove all dirt, loose mill scale and other foreign substances inside the pipeline.
- The swab shall incorporate a steel ring, 6 mm ($^1/_4$ in) thick minimum, with a diameter 3 mm ($^1/_8$ in) less than the nominal inside pipe diameter.
- In the event that the support ring will not pass through a joint, that joint shall not be incorporated in the pipeline. It shall be clearly marked as a reject, then removed from the work site.

9.7.5. Alignment

- The alignment of the abutting ends shall minimize the radial offset. The internal offset between pipe ends shall not exceed 1.6 mm ($^1/_{16}$ in).
- Hammering or heating for correction of alignment is not permitted.
- Internal lineup clamps shall be used when possible and shall not be removed until 100 percent of the root and hot pass is completed.
- When external lineup clamps are used, the equipment shall be approved by Mobil prior to welding.
  - If external lineup clamps are approved, 50 percent of the root pass shall be complete before removing the clamp.
  - In some situations, Mobil may also require the hot pass to be deposited on the root pass before removal of the external lineup clamp.
- Spacer tools shall be used to check final fit-up. The longitudinal welds shall be located in the top 180 degrees of the pipe and have an offset of 152 mm (6 in) minimum.

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9.7.6. Preheat

- The welding procedure shall specify the necessary preheat and interpass temperature, taking materials and welding conditions into consideration. The necessary preheat temperature selection shall be based on welding procedure qualification tests.
- The specific use of preheat shall be approved by Mobil when proper documentation has been submitted. The documentation shall indicate the necessity of preheat, with regard to hardness control and/or prevention of hydrogen-induced, delayed cracking (cold cracking).
- Preheating shall be applied by methods approved by Mobil that are capable of heating the entire circumference of a joint in a uniform manner while avoiding overheating and damage to the pipe's protective coating.
- Measurement of preheat and interpass temperature shall be performed using thermocouples, temperature indicating crayons or other suitable methods approved by Mobil.
- Temperature measurements shall be made on the same locations for qualifications and production welds at least 50 mm (2 in) away from bevel on pipe surface.

9.7.7. Post-Weld Heat Treatment (PWHT)

The necessity for post-weld heat treatment shall be approved by Mobil prior to the start of production welding. If PWHT is required, the procedure shall be approved by Mobil prior to commencement of production welding.

9.8. Repair Welding

- All welding defects with dimensions exceeding the acceptable limits imposed by this Practice shall be removed and repaired according to a qualified procedure after obtaining authorization from Mobil.
- If the total length of the section to be repaired exceeds 30 percent of the weld length, repair by welding shall be refused and the weld shall be cut out. Mobil may, in exceptional cases, authorize the repair of a defect with larger dimensions.
- Repair of cracks shall not be accepted.
- The repair of a repair shall not be allowed.
- The repair station shall be located so that the section of pipe under repair is not in the overbend area or below the pipe tensioner. Repairs in a section of pipe within these areas are not allowed.

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9.8.1. Repair Procedures

Weld repair procedures shall be qualified in the same manner, at the same time and to the same criteria as the weld procedure qualifications. In addition to the details of the procedure qualification, the repair procedure shall contain the following:

- Method of defect removal.
- Preparation of weld cavity.
- Non-destructive inspection method for confirmation of defect removal.
- Maximum and minimum cavity size with the maximum cavity size based on an approved stress correlation function. (The contractor shall present the cavity size and stress correlation calculation for Mobil approval, especially for stress values representative for pipes at repair stations.)

9.8.2. Procedure Qualification

- The repair procedures shall be qualified to simulate repair situations during production welding.
- One set of repair welding procedures shall include, as a minimum:
  - Through-thickness repair
  - External repairs of undercut with one stringer pass
- One set of repair welding procedures shall be qualified for each production welding procedure qualified. The through-thickness repair procedure shall be qualified in accordance with Section 9.5 of this Practice.
- For single pass and stringer repairs, the welds shall be visually inspected, magnetic particle inspected and Vickers Hardness tested. The maximum HAZ hardness shall be 248HV10.

9.8.3. Defect Removal

Weld defects shall be removed by grinding or machining. At the ends and side of the cavity, there shall be a gradual taper from the base of the cavity to the surface of the weld metal.

If weld defects are spaced less than 76 mm (3 in), they shall be treated as a continuous repair. The repaired area shall be dressed by grinding to avoid stress concentrations.

9.8.4. Recapping

- External defects, such as undercut and pin holes, may be recapped provided the procedure qualification has been approved.

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- The recapping shall extend past both ends of the defect.
- All repair welds made during production shall be subject to full non-destruction inspection, in accordance with the requirements of Section 9.9 of this Practice.
- When defect interpretation from radiographic film is insufficient, ultrasonic inspection shall be carried out in addition to visual and radiographic inspection.

9.8.5. Repair Welders

All weld repairs shall only be performed by repair welders specially qualified in accordance with Section 9.6 of this Practice.

9.9. Non-Destructive Testing

The contractor shall furnish all labor, materials and essential equipment necessary for the performance of the work, including critical spare parts and maintain them offshore. Equipment breakdowns or work not in compliance with this Practice shall be at the contractor's expense.

- Equipment shall be serviceable and maintained in good operating condition.
- Materials furnished shall be adequately stored and used in a manner satisfactory to Mobil.
- Any materials or equipment found to be unsatisfactory shall be immediately repaired or replaced at the contractor's expense.
- All equipment and materials supplied under the job specifications shall be new, of proven design and in accordance with sound engineering, fabrication and construction practices. Prototypes, new designs or extensive modification of standard designs are unacceptable.
- Unless otherwise specified in the contract, the contractor shall use an internal X-ray crawler machine for producing radiographs of pipeline production welds on pipe of 305 mm (12 in) diameter and larger.
- External X-ray equipment shall be used to radiograph pipeline production welds of pipe smaller than 305 mm (12 in) diameter. External radiography may be used subject to Mobil approval.

9.9.1. Pipeline Weld Radiographs

All pipeline weld radiographs shall be inspected in accordance with API STD 1104

9.9.2. Permits

The contractor shall be responsible for securing all necessary operational permits needed to comply with the requirements of governing authorities related to the performance of radiographic services.

9.9.3. Radiography

9.9.3.1. Sources

In the event X-ray equipment is used, the contractor shall be responsible for ensuring that the pipe laying barge has sufficient regulated electrical power and adequate space to accommodate the use of such equipment.

If gamma-radiography is employed, the contractor shall use an Iridium 192 radioactive source. The source strength shall be maintained to ensure a maximum exposure duration of 30 seconds per exposure.

9.9.3.2. Film Type

Outdated or expired film emulsions shall not be permitted. All film shall be fresh stock. Only Kodak or a Mobil-approved alternate Class II fine grain and high contrast film shall be used for X-ray radiography. Class I extra fine grain and high contrast film shall be used for gamma-radiography.

9.9.3.3. Penetrameters

Wire penetrameters shall be used. Their thickness, identifying number and placement shall be in accordance with API STD 1104.

9.9.3.4. Illuminators

Only viewing illuminators that can produce light intensity (110 volt-high intensity) sufficient to provide the following result shall be used. All portions of the radiography of the weld and base metal shall transmit sufficient light to reveal the pertinent details of the radiographs having H&D densities up to 4.0. Such equipment shall also be equipped with a variable intensity regulator.

9.9.4. Qualification of Procedure

Prior to the start of radiography, the contractor shall develop detailed radiographic procedures and submit them for Mobil approval. Such procedures shall be developed by a SNT-TC-1A level III qualified technician and be in accordance with API STD 1104.

9.9.4.1. Screens

Lead screens are preferred; however, the use of fluorometallic intensifying screens shall be permitted, subject to procedure qualification. Only fine grain film shall be used. Fluorometallic screens shall be changed out, at the

request of Mobil, when dirt and scratches may influence film quality. Lead screens shall be used for welding procedure qualifications.

9.9.4.2. Quality Indicators

Three radiographs shall be made of the first production weld to establish the quality level for all production radiographs. Mobil acceptance of these radiographs shall result in qualification of the procedure. Should any variables in the procedure specification change, the radiographic procedure shall be requalified.

For procedure qualification, image quality indicators (IQI) shall be placed on both the source side and the film side of the welds. IQI sensibility shall be as follows, based on wire penetrameters:

- Source side: better than 1.8 percent
- Film side: better than 1.6 percent

9.9.4.3. Defect Reports

The defects noted from the radiographs shall be recorded on daily report forms, identical to the forms to be used during the production inspections. Three copies of this report, together with the copies of the test radiographs, plus three copies of the radiographic procedure shall be submitted to Mobil for review and approval.

9.9.5. Production Radiography

Production radiography shall be in accordance with the approved radiographic procedure. Facilities and viewing conditions shall be in accordance with ISO 2504.

9.9.5.1. Qualifications of Radiographers

- Radiographers shall be qualified in accordance with the requirements of ASNT SNT-TC-1A or an approved equivalent.
- Prior to mobilization, the contractor shall furnish Mobil with certificates of qualification for all radiographers to be used.
- Personnel qualification certificates shall be available on site. Personnel without this documentation of qualification shall not be accepted.
- Level II technicians shall be used for interpretation.

9.9.5.2. Film Orientation/Identification

For pipe welded in the fixed horizontal position, the zero datum shall be the top of the pipe. The orientation of the film shall be defined and be the same for all films.

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As a minimum, the film identification shall include the following:

- Client
- Project Number
- Weld Number/Joint Number
- Date
- Radiography Position

9.9.5.3. Interpretation of Radiographs

All interpretations of radiographs shall be made in accordance with the appropriate sections in this Practice governing acceptability of welds.

- The contractor shall provide Level II radiographers who shall be responsible for the interpretation of all radiographs.
- Mobil shall provide independent interpreters who shall review some or all radiographs and provide the final decision on the acceptance, rejection or repair of the radiographs in question.

9.9.5.4. Personnel

Mobil shall have the right to require removal of any employee of the contractor who, in the opinion of Mobil, is incompetent, careless or otherwise not qualified to perform the work assigned; or who may be insubordinate or guilty of improper conduct. The contractor shall immediately replace the employee with another Mobil-approved employee, at no cost to Mobil.

9.9.5.5. Safety Precautions and Protection

The contractor shall be responsible for the protection and monitoring of radiographic personnel and shall ensure that all work is carried out in accordance with the relevant health and safety regulations.

The area exposed to radiation shall be posted.

The contractor's radiographer shall be responsible for the protection and monitoring of all personnel working near X-ray or Gamma-radiation equipment.

- An adequate supply of NRC (Nuclear Regulatory Commission) approved "Danger" or "Caution" signs shall be displayed during any radiographic work on the pipeline.
- It is also the contractor's responsibility to protect the general public and the construction contractor's personnel from harm.

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9.9.5.6. Film Processing

- The contractor shall prepare a procedure for film processing and submit it to Mobil for approval prior to job commencement.
- Film shall be exposed so that the average H&D density shall not be less than 2.0 and the density through the thickest part of the sound weld metal shall not be less than 1.5.
- Radiographs shall be free from all defects caused by bending, dirt, faulty screens, static marks, light leakage and handling. Any film containing defects interfering with the interpretation of the radiograph shall be discarded and the weld shall be re-radiographed.
- Radiographs shall be processed in accordance with API standards to allow storage of film without discoloration for at least three years. The processing chemical shall be changed regularly and care shall be exercised during processing to prevent scratches on the film.

9.9.6. Reports and Records

- A report of the weld interpretation for each shift, along with recommendations, shall be furnished in duplicate for Mobil's signature. The signature will acknowledge Mobil's acceptance of interpretations of the welds. The format of the shift report shall be provided to Mobil for approval prior to mobilization.
- The processed film shall be stored in boxes in a manner that facilitates shipment at Mobil's convenience.
- All radiographic film and the original shift reports prepared by the contractor shall remain the property of Mobil.

9.9.7. Standards of Acceptability

Acceptability for non-destructive inspection shall be in accordance with API STD 1104.

In cases of disputed interpretation of weld acceptability, the decision of Mobil shall be final and the disputed weld shall be repaired or cut out as directed by Mobil.

9.9.8. Disposition of Radiographs

After drying and interpretation, radiographs shall be fastened together and placed in envelopes or boxes in numerical order.

- Each envelope shall be clearly labeled with the number and pipe descriptions of the welds, the date and a copy of the covering report number.

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- Boxes containing numerous envelopes shall have a label on the outside that lists the same information as that required on the envelopes.
- The label shall include the corresponding pipe numbers and descriptions to enable cross referencing of survey station locations for the section of the pipeline covered by the radiography.

9.10. Field Joint Coating

For fusion bonded epoxy (FBE) coated pipeline, the field joint shall also be FBE. The contractor shall submit a proposed field joint coating procedure for Mobil review plus a full description of the proposed epoxy powder, including certified test data. The epoxy powder used for field joint coating shall comply with the requirements stated in MP 20-P-03 and MP 20-P-14. Epoxy powder shall be handled, stored and tested throughout the duration of the job in accordance with the requirements of MP 20-P-03 and MP 20-P-14.

There is some risk of cathodic disbondment of non-FBE coatings with resultant shielding of cathodic protection current and external corrosion of the pipeline. FBE field joint coating minimizes the risk of leaks due to external corrosion.

FBE field joint coating may not always be practical due to lack of space on the lay vessel or for a project with a short design life. Shrink sleeves are commonly used in the industry for coating field joints and are probably the next practical alternative to FBE coating.

9.10.1. Minimum Procedure Requirements

With Mobil approval, the contractor may submit an alternative field joint coating procedure which shall include at minimum the following:

- Product description and material specification
- Prequalification test methods and acceptance criteria
- Quality assurance and control procedure
- Handling and storage procedure
- Installation procedures
- Field inspection, testing and report procedures
- Field repair procedure

Acceptance of any proposed field joint coating system shall be at Mobil's sole discretion.

9.10.2. Essential Properties

The coating applied to girth weld areas shall be compatible with, and have good adhesion to, the yard-applied coating. The coating shall exhibit the same properties as the yard-applied coating in accordance with MP 20-P-03

and MP 20-P-14. The coating applied to repair any small areas of damage to the pipe coating shall be the same type as used in the pipe coating yard for similar repairs.

9.10.3. Joint Preparation

1. Any adherent material that may be left from the cutback of yard-applied coating shall be completely removed.

2. A 500 mm (20 in) band, centered over the weld, shall be washed using fresh water to remove soluble contaminants and then cleaned with an approved emulsifying detergent to remove grease, dirt, etc. Further swabbing with clean solvent shall be used to ensure removal of all contaminants.

3. Weld spatter shall be removed by light grinding or wire brushing.

4. The exposed steel area and approximately 30 mm (1.2 in) wide bands of adjacent yard-applied coating shall be prepared by blast cleaning. The yard-applied coating shall not be removed but shall be lightly abraded immediately adjacent to the blast-cleaned area.

5. A surface finish to SS 05 59 00 shall be obtained with a peak to trough profile height between 50 T and 75 T (2 mil and 3 mil) for the exposed steel area. All areas to be field coated shall, at Mobil's discretion, be salt tested after blast cleaning to check for removal of all salts.

6. The working abrasive shall be maintained free of water, oil, salt and other contaminants. Water/oil traps and filters shall be incorporated in all blast cleaning apparatus.

7. No blast cleaning shall be allowed when the pipe surface temperature is less than 3°C (5°F) above dew point.

8. After blast cleaning, the area to be field coated shall be vacuum cleaned of all deleterious matter. A clean, dry brush may be used to aid cleaning.

9. If jagged or rough edges are left along the edge of the yard-applied coating or if any of the coating is disbonded, then the loose coatings shall be removed until sound coating has been obtained. The area shall then be recleaned.

9.10.4. Coating Process

The coating process shall commence as soon as possible after completion of cleaning procedures and before any visible deterioration of the prepared steel.

1. The coating application area shall be suitably protected from wind, spray, rain, dust, grease, etc. to prevent any contamination of the coating process.

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2. The area to be coated shall be immediately heated by an induction heating coil to a temperature between 230°C and 250°C (446°F and 482°F).

   – The actual temperature range shall be in accordance with powder manufacturer recommendations.

   – If the ambient air temperature falls, it may be necessary to increase the heating temperature to provide adequate curing energy.

   – The carbon steel pipe temperature shall not exceed the limit given by the line pipe manufacturer.

   – The hinged heating coil shall be mounted on the girth weld area and be suitably sized to ensure that the whole weld zone reaches the required temperature.

   – The induction heating equipment shall be approved by Mobil.

3. Suitable trials shall be performed to ensure that the period of heating produces the correct steel temperature. The contractor shall give Mobil the opportunity to witness these trials.

4. Surface temperature shall be checked using thermocouples, indicating crayons or other approved means. The temperature at both "12 o'clock" and "6 o'clock" positions shall be within the acceptable range immediately before commencement of powder application.

5. The epoxy powder shall be sprayed onto the preheated surface by a method approved by Mobil. Adequate safety equipment shall be worn to prevent powder inhalation and eye contact. The contractor is responsible for the safety of personnel.

6. The machine shall travel around the pipe at a uniform velocity using the minimum number of passes necessary to achieve the thickness of coating required.

7. The nominal cured film thickness shall be 0.46–0.56 mm (18–22 mil) for a maximum operating temperature of 60°C (140°F).

8. Overlap of field-applied coating over unprepared yard applied coating shall be avoided.

9. The coating shall be cooled to near-ambient temperature by a Mobil approved method before reaching any pipe-rollers or undergoing any test procedures.

10. The powder level in the spray container shall be monitored to ensure that a sufficient quantity is available to complete an application process.

The powder container, hoses, etc. and the application unit shall be cleaned after each day's work.

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9.10.5. Testing

This Section outlines the minimum test procedure that shall be employed.

- The contractor shall submit a detailed description of the proposed coating test procedure for Mobil approval.
- The first 10 welds to be coated under full production conditions shall undergo the following tests:
  - Coating thickness
  - Holiday detection
  - Adhesion
  - Cure
- Tests shall be conducted and evaluated in accordance with MP 20-P-03 and MP 20-P-14.
- After the first 10 welds are tested as outlined above, additional tests shall be conducted throughout production at the following frequencies:

Holiday detection	every weld
Coating thickness	every weld
Adhesion	once every 10 welds
Cure test sample	once every 10 welds

- All tests shall be carried out whenever a new batch of epoxy is used and at each shift change.
- Coating defects revealed or caused by test procedures shall be repaired in accordance with MP 20-P-03 and MP 20-P-14. Alternatively, Mobil may require the coating in question to be completely replaced.
- A weld coating deemed to require replacement shall be stripped off and the preparation and coating procedures re-implemented.
- Results from the tests shall be matched with pipe joint and weld numbers.

9.10.6. Application of Fillers

The field joint shall be filled with mastic filler material to form a continuous, constant diameter cylinder between adjoining joints of concrete coated line pipe.

The field joint shall provide a smooth surface and have the same outside diameter as the concrete coated pipeline.

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9.10.6.1. Materials

- The final approval of all materials shall be dependent on the satisfactory completion of the procedure qualification tests.
- With Mobil approval, the contractor may propose alternative field joint filler systems.
- For pipeline coated with fusion bonded epoxy and concrete weight coating, the field joint shall also be coated with fusion bonded epoxy in accordance with the requirements of Section 9.10 of this Practice and prior to the application of filler materials.
- The mastic filler shall be fully defined in the contractor's proposal and procedures. As a minimum, the following information shall be given:
  - Manufacture and grade
  - Binder material type and percentage of total weight
  - Softening point (binder)
  - Penetration (binder)
  - Flash point (binder)
  - Specific gravity (binder and mastic blend)
  - Fine filler material type and percentage of total weight
  - Aggregate material type and percentage of total weight
  - Filler and aggregate sieve analyses
- The maximum aggregate particle size shall be 6 mm (0.23 in).
- The flow characteristics of the mastic shall be determined on each batch by a suitable and approved method.
- The mastic shall be supplied on pallets. Each pallet shall be labeled with the manufacturer's name, batch number, date of manufacture and material grade. Any material without this identification shall be rejected and removed from the worksite.
- For hot poured mastic fillers, steel sheet molding forms of sufficient thickness to resist swelling and distortion shall be provided by the contractor, complete with a system of steel banding tapes. For other filler materials, the contractor shall also provide suitable molding forms.

9.10.6.2. Application Procedure

After the fusion bonded epoxy has been inspected in accordance with MP 20-P-03 and MP 20-P-14, a joint mold shall be formed by putting a metal sheet around the pipe at the field joint and strapping it at each end. The ends of the sheet shall have sufficient overlap at the 12 o'clock position and the width

shall be sufficient to provide adequate overlap over the concrete weight coating to avoid leakage of the mastic.

- The mastic shall be poured from a heated kettle at a temperature approved by the manufacturer. It shall fill the joint without damage to or disbondment of, the fusion bonded epoxy.
- The exterior of the form may be vibrated to consolidate the mix, which shall be topped up as required, without causing segregation of the constituents of the mastic.
- On completion of pouring and subsequent topping up operations, the mastic filling-flap opening shall be closed and banded in place. Then the whole assembly shall be sprayed with cold water to assist cooling of the mastic to an acceptable level before immersion in the sea. The contractor shall ensure that the filling flap does not protrude from the mold.

For other filler materials, application of the material shall be in accordance with procedures established by the manufacturer and submitted by the contractor to Mobil for approval.

On completion of field joint coating, the form shall be checked to ensure that the mold is full and that no swelling, distortion or undue leakage has occurred.

9.10.7. Reports

The contractor shall submit inspection reports, in an approved format, for all inspection and testing undertaken.

A record shall be kept of all repairs made by the contractor to the yard-applied coating with relevant pipe length numbers noted.

10. Anodes

The contractor shall install anodes manufactured in accordance with MP 20-P-03 and MP 20-P-14 at intervals specified by Mobil.

Anode installation shall involve installing prefabricated anode pipe joints furnished by Mobil or installing semi-cylindrical pipeline anodes in accordance with the job specifications.

10.1. Semi-Cylindrical Anodes

Semi-cylindrical anodes shall be installed as follows:

1. Fire retardant cloth or other suitable material approved by Mobil, with a minimum thickness of 3 mm ($^1/_8$ in), shall be wrapped around the pipe in the area under the anode and overlap the steel core plates that are to be welded. During anode installation the insulating cloth shall be held in place with a suitable tape.

2. Steel surfaces of the anode core plates to be welded shall be cleaned to bare metal. The contractor shall place and carefully align the halves of each anode on the pipe over the corrosion coating, so that the overlapping core plates are in contact. After checking alignment, the halves shall be drawn together to ensure a tight and secure attachment. The overlapping core plates shall be welded in four places. A 50 x 50 mm (2 x 2 in) section of corrosion coating shall be removed using a coarse file or special Cadweld rasp.

3. Electrical leads shall be attached directly to the steel pipe by the thermite welding process using copper oxide and aluminum powder. The thermite welding charge shall be limited to a 15 gram F33 Cadweld cartridge.

4. After the anode has been installed, the weld area shall be thoroughly cleaned with a wire brush. All exposed steel surfaces of the pipe and anode core plates, plus the thermite weld areas, shall be coated with epoxy patching compound (or Mobil approved equivalent). Care shall be exercised to prevent corrosion coating from touching the outer face of the anode.

5. The anode conductor cables shall be held firmly against the pipe by application of cold-applied self-adhesive tape. The tape shall be spirally wrapped around the pipe toward the anode with sufficient tension to firmly hold the anode pigtails against the pipe. Successive layers of tape shall be continued to where the pigtails are attached to the anode frame. Tape wrapping of the anode shall be avoided.

10.2. Anode Protection

The contractor shall be responsible for the protection of Mobil-installed or supplied anodes during handling, storage and pipelaying. The contractor shall inspect each anode for damage and shall carry out repairs in accordance with Mobil approved procedure.

The contractor shall monitor anodes and leads to ensure that no damage to the anode or installation occurs while passing over rollers and through the stinger. The contractor shall repair damaged anode installations prior to laying the pipe on the seafloor.

11. Protection Coatings—Inspection and Repair

The contractor shall visually inspect all concrete and corrosion protection coatings for damage during all phases of the installation and prior to lowering the pipe into the water in accordance with MP 20-P-03 and MP 20-P-14. Any damage to these coatings observed during this period shall be repaired.

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The contractor shall complete the repair by applying an approved filler placed in a pre-installed metal form to round out the joint coating to the dimensions of the concrete. These repairs shall be completed prior to the overbend area with adequate curing time provided.

Repeated weight coating damage shall be immediately investigated so that the cause can be identified and remedial action taken to Mobil's satisfaction.

11.1. Repair Guidelines

The decision to repair damaged pipe shall be taken on a case-by-case basis. Concrete coating repairs shall be in accordance with MP 20-P-03 and MP 20-P-14. Repairs are not required on a joint if:

1. The total damaged area does not exceed 300 cm^2 (46.5 in^2)
2. The maximum depth of a damaged area does not exceed 25 percent of the total concrete thickness
3. There is less than 20 total damaged areas

11.2. Repair of Corrosion Protection Coating

Corrosion protection coating shall be repaired in accordance with MP 20-P-03 and MP 20-P-14.

12. Risers

The contractor shall fabricate risers in accordance with this Practice and the job specifications. All riser bends shall have a minimum radius of five pipe diameters. Girth welds shall be no closer than 1.5 m (5 ft) from the centerline of any riser clamp.

12.1. Installation

- The contractor shall provide sufficient bracing at installation to prevent the cathodic protection insulating flange from supporting the riser weight.
- Riser clamps shall be installed in accordance with this Practice and the job specifications. If the clamps are to be installed on an existing structure, all marine growth on the structure shall be removed from the structure surface where the clamp is to be located immediately before installation.
- If the riser is installed offshore, it shall be installed in accordance with procedures approved by Mobil.

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12.2. Testing

- Each riser shall be hydrostatically tested as a single unit after fabrication and before installation.
- The test pressure shall be in accordance with the strength test pressure indicated on the Mobil Data Sheets for this MEP.
- The test duration shall be at least four hours with less than 0.2 percent pressure decrease after temperature corrections.
- The final pressure after four hours shall be equal to or greater than the test pressure on the Mobil Data Sheets for MEP.
- There shall be no visible leakage.
- The hydrostatic test shall be witnessed by Mobil.
- If the riser is hydrostatically tested separately, the contractor shall produce a separate test report whose format and general requirements shall be the same as for the overall pipeline test report.

13. Shore Approach

13.1. Included Activities

Shore approach activities shall consist of the following, as applicable:

- Pulling a section of pipeline to shore
- Trenching in foreshore including surf zone and beach
- Dredging
- Burial, using existing bottom soils or borrow materials, including rock protection
- Sheet piling, cofferdams and other temporary works
- Removal and replacement of existing shore rock protection
- Provision of signs marking onshore line route
- Fencing and securing on shore route and construction area
- Restoration of onshore facilities and topography to original conditions
- Other activities specific to the site and project

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13.2. Welding and Coating Requirements

Requirements for field joint welding and coating shall be identical to the requirements given for the offshore line unless otherwise specified.

13.3. Documentation

- The contractor shall provide details of proposed equipment for pulling the shore approach section of line in accordance with Section 4 of this Practice. Refer to Section 8.11, Item 4 of this Practice for capacity of deadman anchors.
- In addition to the procedures, installation manuals, etc. required by Section 5, the contractor shall provide similar documentation for the shore approach as applicable to the specific project and as required by the job specifications.

13.4. Trenching and Burial

- Requirements for trenching, burial, rock protection and all other activities given in this Section shall comply with the project specifications and drawings.
- Trenching and burial requirements shall strictly comply with applicable CFR and/or any other authority having jurisdiction.
- Any obstructions encountered shall be immediately brought to Mobil's attention for resolution. The contractor shall take every precaution not to damage existing obstructions, but in the event of their damage, shall replace or repair them at contractor's cost to Mobil's satisfaction.

14. Post Lay Survey

The contractor shall perform a post lay survey of the pipeline, risers, tie-ins, etc. in order to document the as-built condition of the pipeline system. This survey shall use ROVs equipped with video and position-fixing equipment and/or divers where applicable. The activity shall include, but not be limited to, the following:

- Perform a video survey of the pipeline and subsea assemblies to determine the as-built condition.
- Determine any adverse condition such as spanning, proximity of obstructions, etc.
- Construct details of crossings.
- Remove all construction debris from the seabed.
- Perform an acoustic scanning survey of buried sections of the pipeline.

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- Perform a final as-built survey and prepare as-built drawings for the entire pipeline route showing all pertinent data and submit to Mobil for approval.

14.1. Accuracy

- Accuracy of the survey shall be ±3 m (±10 ft) in the horizontal planes.
- The contractor shall resurvey any areas where post lay conditions such as spanning or insufficient burial depth were previously identified to verify repairs.

14.2. Survey Vessel

- The contractor shall provide a survey vessel(s) to perform the as-built survey and to assist the lay and support vessels during pipeline installation activities.
- The survey vessel shall be continuously on site during the specified operations to monitor the as-laid position of the pipeline system, both in the horizontal and the vertical plane.

14.3. Documentation Requirements

- As-built video surveys shall show both sides of the line and verify the on-bottom conditions, crossing separation, joint markings where visible, etc. The contractor shall document results of the survey activities and transmit them to Mobil on a daily basis.
- The contractor shall prepare scale drawings of all crossings, tie-ins, spans, etc. showing final configuration, mat or rock dump profiles and other explanatory data.
- The contractor shall prepare as-built survey plots showing final horizontal and vertical pipe positions, locations of important features such as anodes, crossings, tie-ins, etc. and other information as requested by Mobil or required by local regulatory agencies.
- The contractor shall provide Mobil with two copies of all survey video tapes. The tapes shall be annotated to show time, date, position and project name. Voice-over commentary may be added to further describe the tape contents. Each tape shall be accompanied with a written log describing contents and summarizing major conditions documented on the video. The contractor shall also provide an index referencing the areas shown on each tape.

15. Maximum Span Lengths and Span Correction

- Maximum permissible span lengths for pipelines are given on the Mobil Data Sheets for this MEP.

- The contractor shall be responsible for surveying the pipeline immediately after pipelay to ensure that no freespan lengths exceed the maximum permissible after pipelaying.
- All spans greater than those shown for Condition No. 2 (Mobil Data Sheets for MEP, Maximum Permissible Span Length) shall be rectified prior to filling the pipeline with water.
- In the event that excessive spans are observed, the contractor shall rectify the spans by "jetting-in" the pipeline, placement of sand/cement bags or by suitably graded gravel/rock dumping.

16. Pipeline Stabilization and Burial

Pipelines shall be placed below the seabed as required by applicable local marine pipeline codes and Mobil.

- The contractor shall bottom-stabilize and/or bury the pipeline where required in accordance with the job description and this Practice.
- The contractor shall use sand/cement bags, rock dumping, grout mattresses, trenching, jetting or other Mobil approved methods to fulfill the requirements of this Section. Sandbags used for stabilization shall be 3:1 sand/cement mix. The ends of the bags shall be folded and sewn.

16.1. Procedures

- The contractor shall include detailed procedures, design drawings and calculations relating to pipeline trenching, jetting, sandbagging or rock dumping operations in the appropriate Installation Manual.
- Design and procedures for jetting and trenching operations shall ensure that excessive stresses are not imposed on the pipeline due to the formation of unsupported spans or contact between the pipeline and trenching/jetting equipment.

16.2. Rock Dumping

- Rock dumping shall be designed so that impingement damage to the pipeline is minimized. Where necessary, a sand pad shall be placed over the line prior to rock placement.
- Rock size shall be selected to ensure that the final cover profile over the pipeline and the fill around or under the line can be achieved.

16.3. Inspection/Testing

- Post-lay trenching and jetting operations shall be continuously monitored by ROV, fixed video cameras or divers.

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- Inspection using ROV or other approved methods shall be made following burial/stabilization activities to verify that the design requirements have been met.
- Hydrostatic testing shall be accomplished after stabilization/burial is complete. Verification of pipeline integrity after laying but before stabilization/burial shall be performed as required by Mobil.

17. Hydrostatic Testing

The contractor shall clean, gauge and hydrostatically test the pipeline and risers in accordance with this Section. The test pressure shall be as specified on the Mobil Data Sheets for this MEP at a test temperature between 2–38°C (40–100°F).

- The contractor shall submit for approval a detailed step by step procedure and testing operations schedule a minimum of six weeks prior to the start of the test . The procedure shall state the required equipment type and size, number and type of pipeline pigs, inhibitor type and quantity and a description of the test monitoring equipment.
- Prior to the start of the hydrostatic test, all riser clamp bolting shall be loose and all riser elbow braces shall be removed. Following the completion of the test, all riser clamps shall be tightened and the riser stop ring shall be in contact with the fixed clamp.
- The testing operations shall be conducted diligently and thoroughly in a safe professional manner in accordance with Mobil approved pipeline testing practices. Any work by the contractor or test conditions deemed by Mobil to be unsafe shall be corrected. The testing operations shall not continue until the unsafe conditions have been corrected to the satisfaction of Mobil. Nor shall the contractor receive additional compensation for time lost due to unsafe conditions.
- If testing is subcontracted, the contractor shall be responsible for supervising the testing operations. Mobil shall witness and approve all tests.
- The resulting stress from the hydrostatic test pressure, combined with other relevant simultaneously acting stresses on the pipeline as given in MP 20-P-01, shall not exceed 96 percent of SMYS.

17.1. Material and Equipment

The contractor shall furnish all materials and equipment for testing, including the following items:

- Temporary pig launchers and receivers
- Cleaning and gauging pigs
- Chemicals and inhibitors
- Test instruments

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- Water strainers and filters
- Fill and pressure pumps
- Meters
- Air compressors
- Scrapers, extra scraper brushes and cups
- All piping incidental to filling, sectionizing and transferring of water
- Portable communications equipment for use by the contractor and Mobil

During the testing operations, the contractor shall furnish a weatherproof enclosure for pressure recorders, calibration equipment and test personnel at the data collection site of each test section. The contractor shall also furnish sufficient lighting in the compressor-pump enclosure and test header areas during periods of darkness when testing operations are in progress.

17.2. Filling the Pipeline

All water injected into the pipeline shall be clean and free from suspended matter.

- A meter of sufficient size and accuracy shall be used to measure the quantity of water injected into the test section.
- Before water is injected into the pipeline, suspended matter in the water shall be extracted by a filter capable of removing 99 percent of all particles 92 T (3.6 mil) in diameter and larger or equivalent to using a 100 x 100 T (4 x 4 mil) wire-mesh screen.
- If foreign material is pumped into the line because of faulty equipment or careless work, the contractor shall flush the line with clean water at no cost to Mobil.
- The test water may be analyzed by Mobil to determine its suitability for use in the testing operations and to determine the water treatment requirements.
  - Corrosion inhibitor, oxygen scavenger and biocide treatment may be used except where environmental discharge problems of hydrotest water prevent their use.
  - Chemical treatments shall be reviewed and approved by a Mobil Corrosion Engineer early in the project to facilitate timely injection of the chemicals into the system.
  - The required chemical additives shall be injected with the water by the contractor (immediately behind the gauging scraper pig) in concentrations sufficient to protect the pipeline for a minimum of 12 months. Any nearby offshore installations involved in water-making operations shall also be notified.

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17.3. Restriction Test

After running the cleaning scraper, a gauging scraper with an aluminum gauging plate shall be forced through the line at a minimum velocity of 1 m/s (3 ft/sec).

- The gauging plate shall be no less than 6 mm ($^1/_8$ in) thick with a diameter not over 95 percent of the minimum ID of the pipe to be tested.
- If the scraper becomes lodged and will not move by the water pressure, the contractor shall repair the pipeline as needed to permit the scraper to make a complete transit at the specified velocity.

Before the contractor can consider the line as having passed the test, the sizing plate used shall be presented to Mobil and written acceptance of the adequacy of the restriction test shall be obtained. A deformed, bent or severely nicked plate shall be evidence of test failure, at the discretion of Mobil.

17.4. Hydrostatic Pressure Test

On satisfactory completion of the restriction test, the contractor shall hydrostatically test each pipeline and riser in accordance with the following test procedures. Test pressure and duration are given on the Mobil Data Sheets for this MEP.

1. The pressure shall be raised to the test pressure specified on the Mobil Data Sheets for this MEP, allowed to stabilize then held for 15 minutes. The rate of pressure increase shall not exceed 100 kPa (15 psi) per minute during all operations.
2. The pressure shall be lowered to approximately 25 percent of test pressure, allowed to stabilize then held for 15 minutes. Rate of pressure decrease shall not exceed 200 kPa (30 psi) per minute during all operations.
3. The pressure shall be raised to an amount approaching the test pressure and again allowed to stabilize before it is finally raised to the test pressure. The pressure shall not decrease more than 0.2 percent after compensating for temperature. None of this or the foregoing shall be included in the test duration.
4. Water shall be injected or withdrawn from the test section to maintain pressure within the specified limits. The volume of these injections and/or withdrawals shall be measured and recorded.
5. Pressure-volume-temperature (PVT) calculations shall be performed to show any observed pressure loss due to a temperature change or a leak.
6. A pressure recorder and temperature recorder shall be used to continuously record the test pressure, fluid temperature and ambient temperature. In addition, pressures shall be read and recorded to the nearest 7 kPa (1 psi), using a deadweight tester furnished by the contractor. The pressure shall be recorded every 15 minutes until it has stabilized; then it can be recorded every 30 minutes.

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17.5. Test Records

The contractor shall furnish all testing equipment, 24 hour recording instruments and all necessary supplies as well as maintain accurate and permanent records. The testing and recording equipment shall be subject to Mobil approval. Pressure recordings shall serve only as information data and may not be used to determine pressure drop for pipeline leakage. Tests shall not be accepted until the specified test duration can be recorded without pressure loss exceeding 0.2 percent of specified test pressure.

- All recorders and dead weight testers shall be calibrated immediately prior to use. Calibration certification shall be provided for each recorder and dead weight tester used. Recorders shall have calibration verified following the hydrotest. Post-test calibration failure for any recorder shall be grounds for the hydrotest to be rejected by Mobil.
- A time-pressure plot and pressure-volume plot shall be made during the pressure test to visually record its progress. This record shall be made using the dead weight pressure measurements and shall be used to determine if the test is satisfactory.
- All records, data and charts clearly marked with the following information shall be furnished to Mobil:
  - Mobil authorized representative
  - Testing contractor's name and authorized representative
  - Description of facilities tested
  - Date and time of test
  - Test pressure and duration
  - Test medium used
  - Explanation of any pressure discontinuities that appear on any chart
  - Signatures of Mobil's and the testing contractor's authorized representatives

17.6. Repair of Defects

- Failures in the line disclosed by the loss of pressure shall be located and repaired by the contractor.
- The contractor shall, at contractor's expense, repair all defects found whether resulting from inferior workmanship or from defective materials furnished by the contractor.
- Repairs by the contractor on defective materials furnished by Mobil shall be compensated on a mutually acceptable basis.
- After repairs have been made, the pressure test shall be repeated until the pipeline and risers have been determined acceptable by Mobil.

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17.7. Sealing the Pipeline

After acceptance of the hydrostatic strength and leak test, the pressure shall be released until atmospheric pressure has been reached.

- Reduction of pressure shall be conducted slowly (205 kPa [30 psi] per minute maximum) to prevent severe piping vibration.
- The contractor may be required to obtain samples of the test water to confirm that the concentration of chemicals is adequate to protect the pipeline from internal corrosion for a minimum of 12 months.
- On Mobil approval of the chemical concentrations, the contractor shall seal the risers with weld caps at the top of the jacket.

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Fire and Gas Detection

MP 70-P-09

July 1998

Scope

This Mobil Engineering Practice (MEP) describes design and application requirements for detection systems sensing fire, flammable/combustible gases and toxic gases.

Version 0

Table of Contents

Scope 1

1. References 5

1.1. MEPS–Mobil Engineering Practices 5

1.2. Mobil Data Sheets 5

1.3. API–American Petroleum Institute 6

1.4. NFPA–National Fire Protection Association 6

1.5. ISA–Instrument Society of America 6

2. Gas Detection Systems 6

2.1. Point Detectors 6

2.2. Open-Path Detectors 8

2.3. Gas Detector Placement 8

2.4. Factors Influencing Detector Performance 11

3. Gas-Release Hazard Assessment 13

3.1. General 13

3.2. Identify Release Scenarios 13

3.3. Identify Ignition Sources 14

3.4. Terrain 14

4. Fire and Heat Detection 15

4.1. Heat Detectors 17

4.2. Smoke (Products of Combustion) Detectors 18

4.3. Flame Detectors 19

4.4. Detector Spacing 19

4.5. Fire Extinguishing System Interface 20

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4.6. Electric Power Sources 20

5. Signaling and Instrumentation 20

5.1. Power Source 20

5.2. Signaling 20

6. Fire Alarm Systems 22

6.1. Fire Reporting 23

6.2. Code Transmitter 23

6.3. Code Numbers 23

6.4. Use of Special Telephones 23

6.5. Manual Fire Alarm Station 23

6.6. General Alarm Signaling Devices 24

6.7. Auxiliary Alarm Signaling Devices 24

6.8. Radio Frequency Systems 24

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Table of Tables

Table 1: Toxic Effects of Various Chemicals 7

Table 2: Materials Causing Signal Degradation 12

Table 3: Performance Influences on Toxic-Gas Point Detectors by Various Gases .. 13

Table 4: Potential Release and Ignition Sources 14

Table 5: Fire Detection Requirements 15

Table 6: Types of Fire Detectors 16

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1. References

The following publications form a part of this Practice. Unless otherwise specified herein, use the latest edition.

1.1. MEPS–Mobil Engineering Practices

MP 32-P-01	General Requirements for Instrumentation
MP 32-P-07	Safety Interlock Systems and Alarms
MP 33-P-02	Electrical - Classification of Hazardous Locations
MP 33-P-15	Electrical - Stationary Batteries & Chargers
MP 33-P-16	Electrical - AC Uninterruptible Power Supply (UPS) System
MP 33-P-32	Electrical - Intrafacility Communication Systems and Alarm Systems
MP 70-P-01	Loss Prevention - Facilities

1.2. Mobil Data Sheets

Mobil Data Sheets	Mobil Data Sheets
T7009C01	Fire & Gas Detection - Fire Alarm Control Panels - Customary Units
T7009C02	Fire & Gas Detection - Detectors & Accessories - Customary Units
T7009M02	Fire & Gas Detection - Detectors & Accessories - Metric Units
T7009C03	Fire & Gas Detection - Audible & Visual Alarms (Fire) - Customary Units
T7009M03	Fire & Gas Detection - Audible & Visual Alarms (Fire) - Metric Units
T7009C04	Fire & Gas Detection - Gas Detectors/Controllers - Customary Units
D7009C01	Fire & Gas Detection - Fire Detection & Alarm Equipment - Documentation Requirements Sheet
D7009C02	Fire & Gas Detection - Gas Detection & Alarm Equipment - Documentation Requirements Sheet
I7009C01	Fire & Gas Detection - Fire Detection & Alarm Equipment - Inspection & Testing Requirements Sheet
I7009C02	Fire & Gas Detection - Gas Detection & Alarm Equipment - Inspection & Testing Requirements Sheet

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1.3. API–American Petroleum Institute

API RP 14C	Recommended Practice for Analysis, Design, Installation, and Testing of Basic Surface Safety Systems for Offshore Production Platforms Fifth Edition; Errata - 1994
API RP 500	Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities First Edition (Supersedes RP 500A, RP 500B, RP 500C)
API RP 55	Recommended Practices for Oil and Gas Producing and Gas Processing Plant Operations Involving Hydrogen Sulfide Second Edition

1.4. NFPA–National Fire Protection Association

NFPA 45	Standard on Fire Protection for Laboratories Using Chemicals (National Fire Codes, vol. 2)
NFPA 72	National Fire Alarm Code

1.5. ISA–Instrument Society of America

ISA S12.13 PT I	Performance Requirements, Combustible Gas Detectors
ISA S12.15 PT I	Performance Requirements for Hydrogen Sulfide Detection Instruments (10-100 ppm)

2. Gas Detection Systems

The design and application requirements for detection systems sensing fire, flammable/combustible gases and toxic gases shall be in accordance with requirements of this MEP, unless superceded by more stringent local regulations.

2.1. Point Detectors

2.1.1. General

The detecting unit included in the sensor head shall provide adequate sensitivity and the stability necessary, under all conditions, to repeat any reading within ±2 percent over the full-scale range.

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"Smart" sensor technology shall be used when selecting gas detection systems. Sensors shall be capable of direct calibration at the sensor head by one person. The selected sensor shall allow calibration at the sensor head without the need to open the detector enclosure. When in the calibration mode, the sensor shall remove itself from the scanning sequence of the control panel and indicate so by a "calibration" LED on the control panel.

- All detectors shall have UL, FM or CSA approval or equivalent. In selecting a detector, the manufacturer's required maintenance/calibration frequency shall be considered.
- Aspiration is preferred to the use of a vacuum pump, since that arrangement eliminates the need for a device dependent on power sources.

2.1.2. Combustible Gas

Fixed-point combustible-gas detectors shall be based on either catalytic combustion technology or infrared absorption technology and shall allow direct readout in percent LFL (lower flammability limit). Detectors shall be capable of initiating an alarm at a minimum of two distinct LFL levels.

- A measurement of 20–25 percent LFL shall result in actuation of both audible and visual alarms.
- The alarm condition shall not be considered cleared until the specific detector reading has dropped below 20–25 percent LFL.
- Operator response shall be required to clear the audible and visual alarms.

Where appropriate, a measurement of 50–60 percent LFL shall initiate protective systems (e.g., fixed fire protection, process shutdown, ventilation, etc.) in addition to alarming.

2.1.3. Toxic Gas

Fixed-point toxic gas detection systems shall have the capability of displaying a readout from zero to full scale, typically in units of ppm (parts per million). The system shall be designed to first alarm (audible and visual) at the Short Term Exposure Limit (STEL) concentration and subsequently alarm at the Immediately Dangerous to Life and Health (IDLH) concentration (see examples in Table 1). The remote sensor shall be capable of being installed away from the transmitter without amplifiers.

Table 1: Toxic Effects of Various Chemicals

Effect Level	H_2S (ppm)	HF (ppm)	Cl_2 (ppm)	NH_3 (ppm)
Threshold Limit Value (TLV–TWA)	10	3	0.5	25

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Effect Level	H_2S (ppm)	HF (ppm)	Cl_2 (ppm)	NH_3 (ppm)
Short Term Exposure Limit (STEL)	15	6	1	35
Immediately Dangerous to Life and Health (IDLH)	100	30	10	300

NOTES: For further toxicity data consult the Material Safety Data Sheet (MSDS).

TLV = Concentrations allowed for eight hours a day (time weighted average) for a working lifetime.

STEL = Maximum concentration allowed for a continuous period of 15 minutes without suffering from intolerable irritation, chronic or irreversible tissue change or narcosis of sufficient degree to increase accident proneness or impair self-rescue.

IDLH = (1994 revised values): Atmospheric concentration of any toxic, corrosive or asphyxiate substance that poses an immediate threat to life or would cause irreversible or delayed adverse health effects or would interfere with an individual's ability to escape from a dangerous atmosphere (OSHA definition).

2.2. Open-Path Detectors

- Open-path combustible-gas detectors shall be capable of initiating an alarm at a minimum of two distinct LFL levels. A measurement of 20–25 percent LFL shall result in actuation of both audible and visual alarms.
  - The alarm condition shall not be considered cleared until the detector reading has dropped below 20–25 percent LFL.
  - Operator response shall be required to clear the audible and visual alarms.
- Where appropriate, a measurement of 50–60 percent LFL shall initiate protective systems (e.g., fixed fire protection, process shutdown, ventilation, etc.) in addition to alarming.
- Open-path toxic gas detection systems shall be designed to first alarm (audible and visual) at the Short Term Exposure Limit (STEL) concentration and subsequently alarm at the Immediately Dangerous to Life and Health (IDLH) concentration.

2.3. Gas Detector Placement

2.3.1. Outdoor Releases

Combustible- or toxic-gas sensors shall be located in accordance with the protection area limitations of the detector manufacturer.

- Sensors shall be located approximately 3 m (10 ft) from the expected emission point, and preferably in the direction of ignition sources and/or populated areas.

- The detector shall be installed in a location accessible for calibration and maintenance, but not in frequently used access ways.
- Placement of detectors shall not interfere with process equipment maintenance.
- Certain areas shall be avoided, such as sample stations where nuisance alarms would negate the effectiveness of the detection system.

See Section 2.4 of this MEP for specific installation considerations with respect to environmental and other influences impacting detector performance.

Special consideration shall be given to the properties of the gas, specifically its vapor density. Detector locations shall take into account the possible flow pattern of the leaking gas or vapor and ventilation system airflow.

2.3.1.1. Guidelines

Within process boundaries, the following guidelines shall be followed:

1. The number of detectors shall be based on the number of potential release sources.
2. A single point detector may be considered for more than one release point; however, Item 3 below and the manufacturer's specification for the sensing area shall be considered.
3. When placing detectors, wind direction and air currents shall be considered. This is especially important when using a single detector for multiple sources.
4. Open-path gas detection shall be considered for sources grouped within the same line of sight (e.g., a pump row). The transmitter and receiver shall be placed 1–2 m (3–6 ft) away from each potential source.
5. If multiple release sources are present in a process unit, then both point and line-of-sight detection may be used.
6. H_2S detection shall be installed in sulfur plants in the following areas:
   a) Thermal reactor on the operating platform
   b) Around the battery limits
   c) Sulfur pit area near the hatch cover
   d) Loading rack areas
   e) Around pumps or compressors handling high concentrations of H_2S (i.e., Over 1,000 ppm)
   f) Sour water strippers–as required where pumps handle sour water
   g) Sour water pumps

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h) Manually operated sour water draws to open sewers

Detector placement for lighter-than-air gases shall be above the release point. Heavier-than-air gases (e.g., C_3^+) require the detector placement to be 300–450 mm (12–18 in) above the grade. Sensors shall be provided with manufacturer-approved rain hoods. Shop fabricated rain hoods are not permitted.

Analyzer buildings located within classified electrical areas shall be provided with point combustible- and/or toxic-gas detection. Care shall be exercised in locating sensors so that the face velocity at the sensor head does not exceed manufacturer specifications.

Additional criteria for the placement of H_2S detectors can be found in API RP 55 and API RP 14C, Appendix F.

2.3.2. Perimeter Detection

Perimeter detection of releases may be considered in areas containing large amounts of light hydrocarbons (e.g., process areas or pressure storage areas) to alert operations to initiate a manual response or to actuate an automatic response (e.g., unit shutdown or firewater spray system).

Detectors may be installed along any unit boundary adjacent to an ignition source. The configuration shall allow coverage of a majority of the unit's equipment through the use of either point or open-path detection.

- Where point detectors are installed, they shall be spaced approximately 9–15 m (30–50 ft) apart.
- Refer to manufacturer data for spacing.
- Depending on the manufacturer, open-path detectors can cover up to 61 m (200 ft).

2.3.3. Indoor Releases

Indoor or partially enclosed installations that may require gas detection (such as turbine enclosures, compressor stations, indoor process units or offshore production platforms) shall be protected with a point detection system. The density of the gas shall be considered when determining whether the detectors shall be located at high or low points in the enclosure. If the building is equipped with HVAC or a ventilation system, a combustible-gas and/or toxic-gas detector shall be located in the inlet to the system.

- In high-temperature enclosures, such as enclosures for gas turbines, a remote sampling head shall be used. A remote sampling head configuration consists of a standard detector located outside the enclosure with the gas sample aspirated to the detector head.

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- Sampling in indoor locations shall be accomplished by diffusion and convection air currents. No pump or other means of forced air movement shall be required for normal application.

2.4. Factors Influencing Detector Performance

Combustible-gas detectors shall be able to perform to the temperature, humidity, air velocity and vibration specifications prescribed in ISA S12.13 PT I. Toxic (e.g., H_2S) detectors shall be able to perform to the specifications prescribed in ISA S12.15 PT I.

2.4.1. Temperature

To minimize temperature effects on gas detection systems, the following precautions shall be followed:

1. Calibrate the detection system at its mean operating temperature.
2. Ensure that all components, including the sensor, are designed for operation within the expected ambient temperature range for the location of the installation.
3. Locate the sensor away from sources of heat, such as furnaces and engine exhausts.
4. Locate the sensor away from sources of steam, which may be released during freezing temperatures, causing condensation and freezing which may, in turn, plug the detector.
5. In high-temperature enclosures, such as those for gas turbines, remote sampling heads shall be used.

2.4.2. Humidity

High humidity conditions may cause corrosion in detectors containing certain metals. Where high humidity conditions exist, corrosion resistant materials such as stainless steels or other alloys, shall be used.

2.4.3. Air Velocity

When locating sensors, consideration shall be given to prevailing winds, heating and cooling system air circulation patterns and effects of other equipment that affect circulation. Widely varying wind directions may warrant the installation of additional sensors.

Sampling in a high-velocity gas stream shall be arranged to conduct a slipstream of the high-velocity gas into a specially designed sensor.

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2.4.4. Vibration

The impact on detector performance due to vibration is typically limited to low frequency and high-amplitude vibration. To alleviate this problem, sensors located in such environments shall be installed on flexible mounts or flexible conduit. Mounting sensors on vibrating equipment or equipment supports shall be avoided.

2.4.5. Exposure to Materials and the Environment

Combustible-gas point detectors shall not be located in oxygen enriched or depleted atmospheres.

2.4.5.1. Signal Degradation

False sensor readings can be reflected when detectors are exposed to certain environments. Table 2 presents a list of materials which shall be avoided when locating combustible-gas point detectors as these materials are known to cause signal degradation.

Table 2: Materials Causing Signal Degradation

Reduce Sensitivity	Reduce Sensor Life
Lead Compounds (e.g., TEL)	Chlorine
Phosphine	Bromine
Dibrorane	Iodine
Silane	Hydrochloric Acid
Trimethyl Chlorsilane	HBr
Hydrogen Sulfide	HI
Hydrogen Fluoride	Trichloroethylene
Boron Trifluoride	Dichlorobenzene
Phosphate Esters	Vinyl Chloride
Silicone	Freons
RTV Sealers	Halons

2.4.5.2. Performance Influences

Table 3 shows a list of gases that have a detrimental effect on toxic-gas point detectors.

Table 3: Performance Influences on Toxic-Gas Point Detectors by Various Gases

Metal Oxide Semi-Conductor Sensors			Electrochemical Sensors
Response Enhancement	**Response Dampening**	**Kills Sensors**	**Response Dampening**
Hydrogen	Ammonia	Silicones	Carbon Monoxide
Ethylene	Sulfur Dioxide	Carbon Monoxide	Chlorine
Mercaptans		Nitrous Dioxide	Hydrogen
Chlorine		Various heavy metal vapors	Nitrogen Dioxide
Acetylene		Various acid vapors	Sulfur Dioxide
		Various caustic vapors	

3. Gas-Release Hazard Assessment

3.1. General

The objective of gas detection systems is to provide early detection of a gas release with a minimum of false alarms and a high level of reliability. To determine the need for detection of flammable and toxic gases, the consequence of each possible release shall be evaluated. To facilitate this evaluation, a hazard assessment method is outlined below.

These guidelines are applicable to:

- Systems containing hydrocarbons, which can form detectable combustible gas mixtures when exposed to ambient conditions (inventories of light ends [e.g., hydrocarbons with vapor pressures above atmospheric pressure at operating temperatures] and volatile flammable liquids [e.g., light naphtha, gasoline and some crudes]).
- Systems containing materials that can generate detectable toxic vapors when exposed to ambient conditions (e.g., sour gas and HF alkylation streams).

3.2. Identify Release Scenarios

Early detection can be accomplished by placing detectors in the proximity of the most probable release sources. Several locations and types of equipment have been identified

as potential leak sources and shall be considered when determining the need for detection. Table 4 lists common sources of a release.

Table 4: Potential Release and Ignition Sources

Release Sources (Ranked in order of decreasing probability)	Ignition Sources
	Continuous Sources:
Pump seals (single seal)	Furnaces
Compressor seals (single seal)	Exposed hot metal surfaces (>600°F)
Safety valves releasing to atmosphere	**Intermittent Sources:**
Heat exchangers with a history of leakage or subject to temperature cycles	Internal combustion engines
Small pipes and connections subject to failure due to vibration or corrosion	Welding and cutting
Flanges	Vehicular traffic
Sewer vents	Railroads
Control valves	Static electricity
Tank seals	Electrical substations
	Areas with a high level of construction/maintenance

3.3. Identify Ignition Sources

Whenever a leak source of combustible gas is identified, sources of ignition such as those listed in Table 4 shall also be investigated. If a potential leak source is within 30 m (100 ft) in any direction of one or more ignition sources, then some type of detection system shall be considered. The leak or ignition source may be either within or outside the actual process unit in question.

Combustible-gas leak sources not falling within this distance may be evaluated on a case-by-case basis. Special consideration shall be given to remote areas that are infrequently attended. Dispersion modeling can be used to calculate gas travel distances.

3.4. Terrain

When heavier-than-air gases are being monitored, grading of the area around the release source shall be considered. Ignition sources within 30 m (100 ft) or downgrade from a release source shall be identified. Drainage ditches and other low points shall be considered for both combustible- and toxic-gas monitoring.

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4. Fire and Heat Detection

Automatic fire detectors are not usually installed in process areas. However, these devices shall be provided at remote, high-risk facilities such as offsite charge, shipping and transfer pumps, crude oil tank mixers, computer rooms and operations with limited manpower or automated unattended operations. A summary of fire detection requirements is given in Table 5.

Table 5: Fire Detection Requirements

Occupancy	**Type of Fire Anticipated**	**Fire Alarm Manual Station**	**Recommended Type of Detection***	**Alarm Location**
Process Units	Fast	Yes	None	Plant fire alarm
Offsites				
Crude and flammable pumps in remote area	Fast	No	Heat (fixed temp) or flame (UV/IR)	Main process control room
Storage tank mixers	Fast	No	Heat (fixed temp)	Process or oil movement control room
Truck loading rack	Fast	Yes	Heat (fixed temp) or flame (UV/IR)	Dispatcher's office and plant fire house
Enclosed buildings handling flammable liquids or gases	Fast	Yes	Heat (fixed temp) or flame (UV/IR)	Local and plant fire house
Enclosed buildings handling combustible Class III liquids	Moderate	Yes	Heat (rate of temp rise)	Local and plant fire house
Control buildings				
Computer area	Slow to moderate	Yes	Smoke (ionization; crosszone system–see MP 70-P-01)	Local and plant fire house
Laboratories	Moderate to fast	Yes	Heat (rate of temp rise)	Local and plant fire house

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Occupancy	Type of Fire Anticipated	Fire Alarm Manual Station	Recommended Type of Detection*	Alarm Location
Office area cut-off from control	Slow	Yes	None	Local and plant fire house
Control room and office area in control room	Slow	No	None	Plant fire alarm
Electrical switchgear room in cut-off area	Slow	No	Smoke	Local and plant fire house
Warehouses (other than bulk plants and plastic plants)	Moderate to fast	Yes	(see MP 70-P-01)	Local and plant fire house
Computer centers	Slow to moderate	Yes	Smoke (ionization; crosszone system– see MP 70-P-01)	Local and plantfire house or public fire department
Administration buildings	Slow	Yes	None	Local and plant fire house
Shops and miscellaneous structures	Slow to moderate	Yes	None	Local and plant fire house
Laboratory buildings	Slow to moderate	Yes	None	Local and plant fire house (for evacuation, see NFPA 45)
Switchgear and substation	Slow	Yes	Smoke (ionization)	Local and plant fire house

* See Table 6 for recommended types of fire detectors.

Table 6: Types of Fire Detectors

Heat Detectors	Smoke Detectors	Flame Detectors
Fixed temperature	Photoelectric	Combination Ultraviolet/Infrared***
Fusible plugs or sprinkler heads with pressurized tubing or pipe*	Refraction	

Heat Detectors	Smoke Detectors	Flame Detectors
Nylon pneumatic tubing*	Ionization**	
Fusible links and quartzoid bulbs	Resistance bridge	
Thermostats:		
Bimetallic strip		
Snap-action disk		
Thermostatic cable		
Continuous discrete conductors		
Thermistor sensors		
Rate of temperature rise		
Copper tubing heat-actuated devices (HADs)		
Thermoelectric		
Combined rate of rise/fixed temperature		
Rate compensation		

* Recommended type for outdoor plant installation

** Recommended type for computer rooms

*** Recommended type for tank truck loading racks

A number of factors shall be considered in the design of a reliable fire detection and alarm system. A vendor's proposal for installation shall include:

1. Data on the nature and arrangement of power sources
2. Coverage provided by the system
3. Alarm function on loss of system operability
4. Suitability of detection devices for the risk involved
5. Testing and maintenance procedures to ensure a fully reliable fire detection and alarm system

All fire detection system circuits shall be fully supervised for malfunctions. Circuit malfunctions shall cause the sounding of a separate and distinctive trouble signal and the operation of a trouble-signal lamp.

4.1. Heat Detectors

Heat detectors fall into two general categories: fixed-temperature devices and rate-of-rise devices.

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4.1.1. Fixed Temperature Devices

Fixed temperature devices respond when the detection element reaches a predetermined temperature.

4.1.2. Rate-of-Rise Devices

Rate-of-rise devices respond to an increase in heat at a rate greater than a predetermined value.

Some devices combine both principles. The same principles apply regardless of whether the devices are of the single-spot type or are continuous along a line or circuit.

- The rate-of-rise detectors have the advantage of being set to operate more rapidly than fixed-temperature devices, and the former are effective over a wide range of ambient temperatures.
- Rate-of-rise detectors will also tolerate slow changes in ambient temperature.
- A disadvantage sometimes associated with rate-of-rise detectors is the need to be careful to install them away from possible heat sources to avoid false fire signals. The use of weatherproof rate-of-rise detectors greatly reduces maintenance costs and false alarms when located close to steam lines and heaters.

4.2. Smoke (Products of Combustion) Detectors

- Smoke detectors operate on various principles, including photoelectric obscuration, ionization of smoke particles, resistance changes in a chamber and optical scanning of a cloud chamber.
  - Recommended types are the ionization or photoelectric obscuration detectors.
  - Linear beam smoke detectors, which employ an obscuration detection principle using an infrared beam, may also be used, particularly, in areas of high air movement.
- Smoke detectors tied into a central alarm system shall have a lamp on each detector head capable of indicating an alarm condition.
  - Any hidden detectors shall remotely annunciate to a display in the protected area. All single detectors shall generate an alarm.
  - When smoke detection systems are installed to actuate equipment shutdown and/or extinguishing systems, they shall be arranged with a cross-zoning or voting array.

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- Magnetic door hold-open devices shall be placed on doors that are required to close in the event of a fire. System logic shall ensure that smoke detection in a given area will close all appropriate doors.

4.3. Flame Detectors

Two types of optical detection devices incorporate light-sensitive cells responsive to infrared (IR) or ultraviolet (UV) radiation at different wavelengths. Combination UV and IR detectors are recommended. Such detectors shall only annunciate an alarm when both UV and IR radiation of the proper proportions and wavelengths are detected. The selected UV/IR detectors shall be capable of automatic optical integrity checks (i.e., "through the lens" self-checking) and shall be arranged to initiate a trouble alarm in the event of lens blockage.

- IR detectors shall detect radiation wavelengths in the 4.1–4.6 micron wavelength region.
- Combination UV/IR detectors shall annunciate an alarm when the radiation wavelengths specified above are detected in a ratio specific to the fuel source and fire.
- Such detection logic will provide a highly reliable detection system, relatively free of false alarms.

IR-only or UV-only detectors shall not be used due to the high incidence of false alarms.

4.4. Detector Spacing

To function effectively, detection devices, particularly the spot, fixed-temperature, heat-type devices, must be properly positioned. Detailed requirements for spacing can be found in NFPA 72 (Part E). These spacing requirements are based on limitations contained in UL listings and/or FM approval lists.

- Where detectors manufactured outside the United States are used, the spacing recommendations of the local authority with jurisdiction, taking into account the manufacturer limits on the product, shall be followed.
- Where process equipment is protected by fixed-temperature spot detectors, these shall be located as close as possible to the potential fire source; for example, above flammable liquid pump seals, immediately over a solvent draw-off point or mounted above a crude tank mixer stuffing box. As a general rule, fixed-temperature spot detectors at a point of potential hazard shall be considered only for process equipment with which specific fire problems are anticipated.
- Where equipment and processes are protected by flame (UV/IR) detection, the manufacturer requirements for detector line of sight and spacing shall be followed.

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4.5. Fire Extinguishing System Interface

Where a detection system is part of an automatic, fixed fire-extinguishing system, complete compatibility between the systems is essential. Fire detection devices and systems that are highly susceptible to false alarms shall be avoided, especially when they are connected to fixed fire extinguishing systems. Fire detection and control panels used to trip fire extinguishing systems shall be UL listed and/or FM approved for such purposes.

4.6. Electric Power Sources

Electric power shall be available from two highly reliable sources. The usual arrangement is an alternating current (AC) power supply, with trickle charger supplying a battery backup system.

- Meters shall be provided to monitor charging current and battery voltage levels.
- Batteries shall be sized for loss of primary power for a period of no less than eight hours, and for at least 12 hours if the main power supply is not reasonably reliable. An exception is power for alarm bells or horns, which require only one hour of battery backup power.
- The power supply shall be monitored by a power-on lamp on the control panel and a main power failure alarm.

5. Signaling and Instrumentation

5.1. Power Source

Detection system power shall be provided by an uninterruptible power supply (UPS), in accordance with MP 33-P-16 or by on-line battery power in accordance with MP 33-P-15. Batteries shall be sized to provide power for all detection systems for 24 hours and audible alarms for one hour, in addition to any other loads on the system.

An LED shall be provided to indicate the power is on and the system is operating correctly. Upon power failure or interruption, an audible and visual alarm shall be provided to indicate that a system reset is required.

5.2. Signaling

Sensor signals to the central control panel shall be immune to radio frequency interference (RFI) and electro-magnetic interference (EMI). The alarming and actuation systems shall be installed in accordance with MP 32-P-01, MP 32-P-07 and MP 33-P-32 as applicable.

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Each sensor shall have a unique address that permits multiple sensors to transmit signals to the control panel on a common cable (multiplexing).

Each sensor shall annunciate individually to an analyzer control panel. Multiple sensors connected in series to a single analyzer are not recommended when the output from each detector is cumulative.

5.2.1. Component Supervision

All system components shall be supervised. An LED on the control panel shall provide visual and audible indication of system trouble. The system shall be supervised for:

1. Calibration due
2. Low battery power
3. Sensor head failure
4. Ground fault or wiring failure on sensor circuits
5. Alarm circuit failure
6. Control board failure

5.2.2. Readouts and Alarms

- All readouts and alarms shall annunciate to a fully manned location, if available, such as the central control center.
- Fire and gas detection shall result in separate and distinct audible and visual alarms at a control point and an audible alarm for the affected area.
- In a high noise environment (i.e., 90 dBA or greater), a separate distinct visual alarm shall be required in the affected area.
- Local visual alarms shall be visible from 360 degrees. A strobe is preferred, but a rotating beacon is acceptable.

5.2.2.1. Visual Alarms

The suggested color codes for visual alarms are:

- Red: Fire
- Blue: Combustible gas
- Amber: Toxic gas

For gas detection systems, visual and audible alarms shall be provided for two levels of detection. Silencing of the audible alarm shall not deactivate the visual alarm until detection falls below the alarm level. Visual and audible alarms shall be different for each level of detection.

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5.2.2.2. LEL Readout

Sensors' digital readout in percent LEL (lower exposure limit) for combustible gases and ppm for toxic gases shall be provided as follows and shall be selectable at the control panel:

- Scan mode: Highest sensor concentration to lowest sensor concentration scan when in alarm
- Selected sensor

5.2.2.3. Overall Display

When specified, an overall display of the fire detection system shall be provided in the control room or other continuously manned location. Separate detection zones shall be provided for each distinct fire area. The overall display shall locate any alarm on a plot plan graphic.

5.2.3. Alarm Test and Reset

The control panel shall provide a sequential test for all sensor alarms. An alarm silence shall not reset the system. A separate reset button shall be provided.

5.2.4. Interlocks with Other Equipment

Gas and fire detection systems shall include necessary logic and actuators to initiate applicable systems, e.g., ventilation, process shutdowns or operation of fixed fire suppression systems. See MP 32-P-07 for interlock system details.

5.2.5. Zoning

Where possible, detectors shall be cross-zoned to minimize the potential for false alarms. This is of particular concern when detectors are interlocked with other equipment.

5.2.6. Electrical Area Classification

The detection equipment shall be electrically classified as required by MP 33-P-02.

6. Fire Alarm Systems

A means of reporting fires and alerting the plant fire brigade shall be provided. The system shall be as simple as possible to minimize the potential for confusion in emergencies. The preferred design is

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a coded signal system with coded transmitter that signals in the control room and activates a steam whistle or air horns.

6.1. Fire Reporting

Fire reporting can be achieved by means of the telephone system through a dedicated telephone number restricted to that purpose. In areas without telephone sets or in large, widely separated facilities, manual fire alarm stations (see Section 6.5) can be installed in lieu of, or to supplement, the telephone reporting system. Telephone systems shall be provided with backup electric power in accordance with Section 4.6 of this MEP.

6.2. Code Transmitter

A code transmitter shall be installed in the central control room to provide the signal for the general alarm. A variable, four-digit code transmitter, such as the Gamewell Peerless Manual Transmitter, is approved for this purpose.

6.3. Code Numbers

The plant shall be divided into a grid system, with each module identified by a number. Code numbers shall include two digits (l-3, 2-9, etc.) and, where possible, shall be related to an operating unit or building number.

6.4. Use of Special Telephones

When this system is used, a special telephone shall be installed in the central control room to receive fire and emergency notification. This telephone shall be capable of receiving incoming calls only and shall be colored red to distinguish its purpose.

Telephone extensions may also be provided in strategic locations, such as the fire station, guard headquarters, shop or laboratory offices, or other locations with preliminary emergency responsibilities. Extensions shall not prevent the operation of the central control room telephone if the remote receiver is removed from its cradle.

An incoming call on the telephone shall be audibly and visually annunciated in a distinctive manner so that a code transmitter can be properly energized manually if not arranged for automatic operation.

6.5. Manual Fire Alarm Station

Although a coded alarm system is preferable, either a coded system or a non-coded annunciator-type system can be used. Either system can consist of telephones or manual fire alarm stations at strategic locations.

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Manual fire alarm stations shall be located throughout the protected area so that they are unobstructed and readily accessible in the normal path of exit from the area.

- Coded manual fire alarm stations can be connected to the general alarm to sound a coded signal without manual intervention.
- Non-coded stations can be arranged to show fire location on a fire alarm annunciator panel in the control room so that the operator can energize the code transmitter.

Both systems shall be controlled from a fire-alarm control panel.

6.6. General Alarm Signaling Devices

The main alarm system for a process plant shall consist of one or more air horns strategically located to ensure maximum coverage throughout the plant. Air horns, such as those available from the Federal Sign & Signal Corporation, are recommended. The alarm signal shall be clear, audible, distinctive from similar signals used for other purposes and capable of being heard in all plant areas regardless of background noise.

Air consumption by the air horns may vary between 6–40 dm^3/s (0.2–1.4 ft^3/s). Air pressure requirements vary with horn size, and units are available for operating pressures in the range of 138–1,035 kPa gauge (20–150 psig). A reserve air supply suitable for operating the air horn for a period of five minutes shall be provided. Automatic switching from the main supply to reserve supply shall be provided and initiated by main air supply failure. Instrument air is recommended for the main air supply.

6.7. Auxiliary Alarm Signaling Devices

For indoor locations or remote areas where the general alarm air horn cannot be heard, auxiliary alarm devices shall be provided. These alarms, also activated by the code transmitter, can be bells, or air or electric horns. They shall be the same in all areas of a plant and shall be distinct from other warning horns or bells.

6.8. Radio Frequency Systems

In some locations, radio frequency systems or pagers are used to notify offsite personnel of an emergency. When provided, such systems shall have a backup electric power supply in accordance with Section 4.6 of this MEP. Where paging systems are accessed by telephone, backup electric power shall also be provided for the telephone system.

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Fireproofing

MP 70-P-05

July 1998

Scope

This Mobil Engineering Practice (MEP) covers basic requirements for fireproofing applied to vessels, structures, buildings, walls, bulkheads and the supporting elements of equipment and piping in areas where flammable liquids and gases are processed, handled and stored. It does not cover the assembly of specific building materials to create inherently fire-resistive structures or building components.

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Table of Contents

Scope **1**

Table of Tables **4**

1. References **5**

1.1. MEPS–Mobil Engineering Practices 5

1.2. ASTM–American Society for Testing and Materials 5

1.3. ICBO–International Conference of Building Officials 5

1.4. NFPA–National Fire Protection Association 6

1.5. UL–Underwriters Laboratories 6

2. Structures and Equipment–Fireproofing Specifications **6**

2.1. Fire-Exposed Envelope 6

2.2. Fireproofing Ratings 7

2.3. Steel Support Elements 8

2.4. Concrete Structures 12

2.5. Equipment 12

2.6. Offshore Process and Accommodation Areas 12

2.7. Offsite Areas 14

2.8. Buildings 14

3. Structures and Equipment–Materials and Application **15**

3.1. General 15

3.2. Application 15

3.3. Concrete 17

3.4. Lightweight Concrete 18

3.5. Preformed/Inorganic Panels 19

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3.6. Concrete Masonry 19
3.7. Fireproofing Mastics 19
3.8. Thermal Insulation 21
3.9. Magnesium Oxychloride Plasters 22
3.10. Wrap-Type Systems 22
4. Instrumentation, Electrical and Valve Operators 22
4.1. Main Instrument Runs 22
4.2. Tubing, Conduit and Valve Operators 25
4.3. Power Cables 26
5. Quality Control 27
5.1. Monitoring and Inspection 27
Appendix A: Fire Resistance Ratings 28
Appendix B: Suggested Fireproofing Materials 30

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Table of Tables

Table 1: Fireproofing Ratings–Structures and Equipment 7

Figure 1: Fireproofing Steel Structures 10

Figure 2: Pipe Rack in Process Area 11

Table 2: Classes of Fire Resistance 13

Table 3: Example Surface Preparations 16

Table A–1: Fire Resistance Ratings 28

Table B–1: Fireproofing Materials 30

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1. References

The following publications form a part of this Practice. Unless otherwise specified herein, use the latest edition.

1.1. MEPS–Mobil Engineering Practices

MP 01-P-07	Concrete-Design & Construction
MP 34-P-10	Thermal Insulation - Hot Service
MP 34-P-11	Thermal Insulation - Cold Service
MP 35-P-01	Painting - General Requirements
MP 70-P-01	Loss Prevention - Facilities
MP 70-P-03	Hazard Assessment
MP 70-P-07	Firewater Systems and Devices

1.2. ASTM–American Society for Testing and Materials

ASTM C150	Standard Specification for Portland Cement
ASTM D3359 REV A	Standard Test Methods for Measuring Adhesion by Tape Test
ASTM E96	Standard Test Methods for Water Vapor Transmission of Materials
ASTM E119 REV A	Standard Test Methods for Fire Tests of Building Construction and Materials

1.3. ICBO–International Conference of Building Officials

ICBO UBC-1997-LL	1997 Uniform Building Code (3 Volumes – Loose-leaf)

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1.4. NFPA–National Fire Protection Association

NFPA 15	Standard for Water Spray Fixed Systems for Fire Protection (National Fire Codes, vol. 1)
NFPA 30	Flammable and Combustible Liquids Code (Includes Tentative Interim Amendment - 1996) (National Fire Codes, vol. 1)
NFPA 220	Types of Building Construction

1.5. UL–Underwriters Laboratories

UL 1709	UL Standard for Safety Rapid Rise Fire Tests of Protection Materials for Structural Steel Second Edition; February 16, 1994

2. Structures and Equipment–Fireproofing Specifications

The basic requirements for fireproofing applied to vessels, structures, buildings, walls, bulkheads and the supporting elements of equipment and piping in areas where flammable liquids and gases are processed, handled and stored shall be in accordance with requirements of this MEP, unless superceded by more stringent local regulations.

2.1. Fire-Exposed Envelope

Fireproofing specifications contained herein apply to the specified types of equipment and/or supports located within a fire-exposed envelope.

- A fire-exposed envelope is the area within 9 m (30 ft) horizontally and 12 m (40 ft) above any high fire potential equipment or the limits of a potential pool or stream of burning liquid.
- When high fire potential equipment is located above grade, the distance below (to grade) is also considered to be within the envelope.
- The size of the envelope shall be increased when there is a potential for a fire to exceed the limits specified herein.
- Where a process is carried out in the gas phase and there are no inventories of flammable liquids, the fire-exposed envelope may be reduced. In these cases, fireproofing shall be selectively applied to protect against jet type fires.

2.1.1. High Fire Potential Equipment

High fire potential equipment includes vessels, pumps, compressors, heat exchangers, fired heaters and similar equipment containing flammable or combustible liquids and/or vapors. Classification of flammable and combustible liquids shall be in accordance with NFPA 30.

Piping generally is not considered high fire potential equipment except where numerous flanges exist or the ability to quickly detect and isolate a spill is lacking.

2.1.2. Low Fire Potential Equipment

Low fire potential equipment is equipment with small inventories of flammable or combustible liquids or stationary equipment with minimal potential for leaks. This includes knockout and blowdown drums isolated from other high fire potential equipment.

2.2. Fireproofing Ratings

Fireproofing ratings for process plant structures and equipment are indicated in Table 1, with further details for each given in the referenced Section.

Table 1: Fireproofing Ratings–Structures and Equipment

Structures and Equipment	UL 1709 Fire Test (Hydrocarbon Fire)	Reference Section
Steel structures supporting equipment or offshore platforms	1 hour	2.3 (Items 1,2,3,4) & 2.6
Main pipe racks inside process units	30 minutes	2.3 (Item 5)
Main pipe racks in process units supporting equipment	1 hour	2.3 (Item 6)
Structural supports for process unit transfer lines	1 hour	2.3 (Item 7)
Piping supported from hangers	1 hour	2.3 (Item 8)
Equipment supports (skirts, legs, etc.)	1 hour	2.3 (Item 9)
Flue gas stack supports	1 hour	2.3 (Item 10)
Nonferrous metal equipment	1 hour	2.3 (Item 11)
Crude desalters and reactors	1 hour	2.5

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Structures and Equipment	UL 1709 Fire Test (Hydrocarbon Fire)	Reference Section
Aluminum vessels in cold service	1 hour	2.5
Main instrument runs	15 minutes	4.1
Tubing, conduit and valve operators	15 minutes	4.2
Firewalls between offshore process areas and other process areas	H-0	2.6
Firewalls between offshore process areas and wellheads	H-0	2.6
Firewalls between offshore process areas and accommodation areas	H-120	2.6
Firewalls in offshore accommodation areas	A-30, 60 or 120	2.6

2.3. Steel Support Elements

Steel support elements located within a fire-exposed envelope shall be fireproofed. Such elements may be protected by a fixed water spray system in lieu of fireproofing only when approved by Mobil. Unless otherwise noted, steel structures and equipment supports shall be protected for the duration stated in Table 1.

1. When supporting high fire potential equipment, columns and beams shall be fireproofed. Columns and beams that transmit the equipment load to columns shall be fireproofed from grade up to the equipment support level (see Figure 1–A). When low fire potential equipment is located at a higher level, the fireproofing shall be extended 12 m (40 ft) above the level at which high fire potential equipment is supported (see Figure 1–C).

2. When supporting low fire potential equipment, the structure shall be fireproofed from its base up to the platform or horizontal bracing plane nearest to an elevation of 12 m (40 ft). However, the fireproofing shall not terminate below 10.5 m (35 ft) (see Figures 1–B and 1–C).

3. Knee and diagonal bracing that contributes to the support of vertical loads or stability of columns shall be fireproofed. Knee and diagonal bracing used only for wind loading need not be fireproofed (see Figure 1–C).

4. The top surface of a beam that requires fireproofing need not be fireproofed when that beam supports steel flooring or piping.

5. When main process area pipe racks and interconnecting pipe racks support piping only, they shall be fireproofed from their bases up to and including the first level of

pipe support. Wind bracing and structural steel stringer beams running parallel to piping need not be fireproofed (see Figure 2–A).

6. Main pipe racks that support equipment such as air coolers shall be fireproofed from their bases up to and including the equipment support legs and the horizontal beams transmitting the equipment load to the columns (see Figure 2–B).

7. Structural steel supports for process unit transfer lines shall be fireproofed with 50 mm (2 in) of concrete conforming to Section 3.3 (see Figure 2–C). Equivalent fireproofing may be used with Mobil approval.

8. In fire-exposed areas, piping supported from spring hangers or rods shall be protected against failure of the hanger or rod by a bracket or beam located beneath the pipe (see Figure 2–D). The bracket or beam shall be fireproofed with 50 mm (2 in) of concrete. Sufficient clearance between the bracket and pipe shall be provided to permit free movement of the spring hangers. Where the use of the bracket is not practical, spring hangers and rods may be fireproofed with preformed pipe insulation. Insulation shall be weatherproofed.

9. Structural members that support equipment shall be fireproofed, including the following:

   a) Legs and lugs or anchor bolts of vessels containing flammable or combustible liquids or vapors.

   b) Vessel skirts, inside and outside, except skirts less than 1.2 m (4 ft) in diameter with only one access opening, need not be fireproofed on the inside surface.

   c) Legs for air coolers supported from ground level.

   d) Support legs for pressure storage spheres.

   e) Supporting structures for pressure storage cylinders.

   f) Steel support legs for process heaters.

   g) Vessel and equipment steel saddle supports exceeding 0.6 m (2 ft) in height at the center.

10. When central chimneys or stacks are designed to receive flue gas from several heaters, the structural supports for the flue gas ducts between the heaters and stack shall be fireproofed.

11. Nonferrous metals (such as aluminum, copper and other low-melting-point metals) used for equipment in hydrocarbon service shall be fireproofed. Nonferrous piping shall be fireproofed only when required in project specifications.

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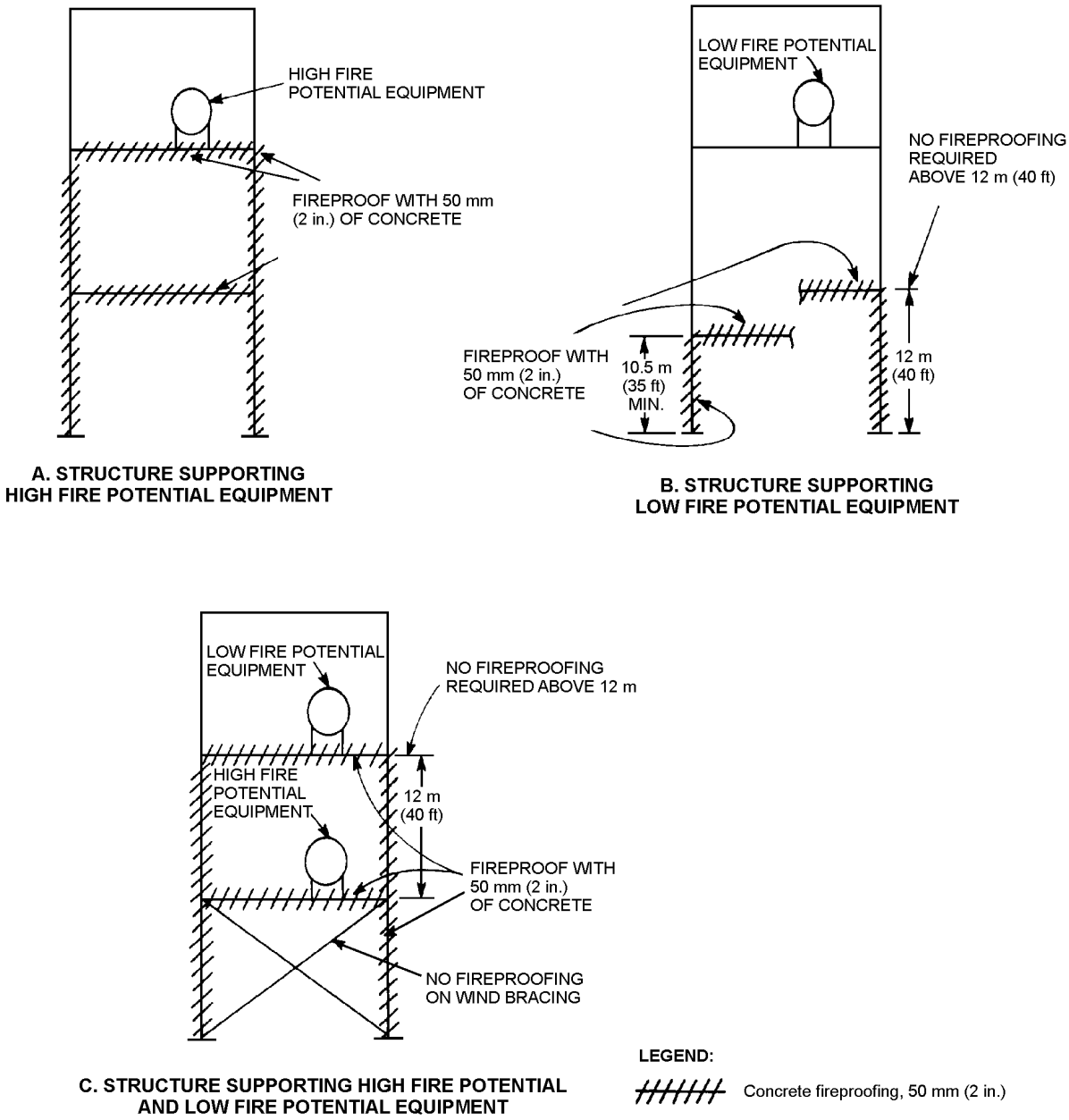

Figure 1: Fireproofing Steel Structures

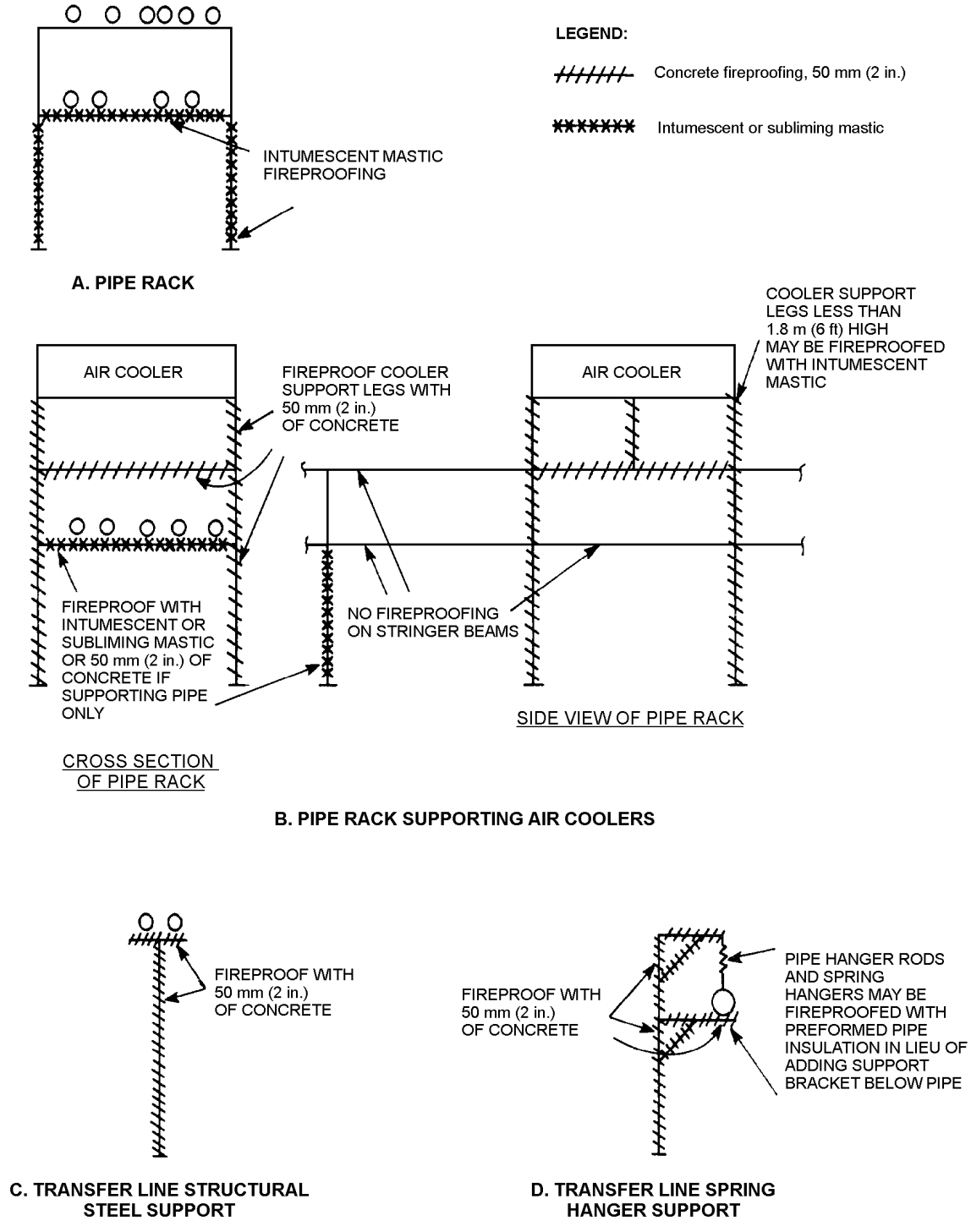
LEGEND:
Concrete fireproofing, 50 mm (2 in.)
Intumescent or subliming mastic
INTUMESCENT MASTIC FIREPROOFING
A. PIPE RACK
AIR COOLER
FIREPROOF COOLER SUPPORT LEGS WITH 50 mm (2 in.) OF CONCRETE
AIR COOLER
COOLER SUPPORT LEGS LESS THAN 1.8 m (6 ft) HIGH MAY BE FIREPROOFED WITH INTUMESCENT MASTIC
FIREPROOF WITH INTUMESCENT OR SUBLIMING MASTIC OR 50 mm (2 in.) OF CONCRETE IF SUPPORTING PIPE ONLY
NO FIREPROOFING ON STRINGER BEAMS
CROSS SECTION OF PIPE RACK
SIDE VIEW OF PIPE RACK
B. PIPE RACK SUPPORTING AIR COOLERS
FIREPROOF WITH 50 mm (2 in.) OF CONCRETE
C. TRANSFER LINE STRUCTURAL STEEL SUPPORT
FIREPROOF WITH 50 mm (2 in.) OF CONCRETE
PIPE HANGER RODS AND SPRING HANGERS MAY BE FIREPROOFED WITH PREFORMED PIPE INSULATION IN LIEU OF ADDING SUPPORT BRACKET BELOW PIPE
D. TRANSFER LINE SPRING HANGER SUPPORT

Figure 2: Pipe Rack in Process Area

2.4. Concrete Structures

Concrete structures constitute a unique category, as follows:

- Reinforced concrete structures do not require fireproofing unless specified otherwise.
- Prestressed concrete structures located in fire-exposed areas normally require fireproofing to prevent relaxation of the tensioned steel rods or wire due to thermal expansion. However, these structures are not within the scope of this Practice, as they require special protection, such as an intumescent coating or block insulation covered with a stainless steel jacket or water sprays.

2.5. Equipment

Fireproofing requirements for equipment are as follows:

- Crude desalters (which contain large quantities of Class I liquid hydrocarbon) and externally insulated reactors (which usually constitute critical process equipment) that are insulated for heat conservation shall be fireproofed with insulation and jacketing as specified in Section 3.8. Other vessels shall be fireproofed only when required by Mobil.
- Vertical vessels shall not be fireproofed unless required by Section 2.3 (Item 9) or this Section.
- Aluminum vessels in cold service shall be fireproofed.

2.6. Offshore Process and Accommodation Areas

Fireproofing shall be applied to key items of equipment and the platform structure when it constitutes the most effective form of fire protection.

2.6.1. Fire-Exposed Envelope

Where fire potential sources are located on solid decks or other solid surfaces, the fire-exposed envelope shall be as defined in Section 2.1. Where the potential exists for spillage of hydrocarbons onto levels below the fire-exposed source, such lower levels shall also be considered as being fire-exposed.

For those portions of the platform provided with open grate decks, the fire-exposed area shall be determined by reference to the hazard assessment. The ability of fire potential equipment to develop credible pressure fires shall be reviewed and the fire-exposed area established accordingly.

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2.6.2. Fire Resistance Class

In offshore installations, the class of fire resistance to be provided for barriers and walls shall be established by determining the type of operations on either side and then referring to Table 2. Reference shall also be made to the hazard assessment to establish whether any criteria have been set for the precise specification of certain classes of barriers.

Table 2: Classes of Fire Resistance

Location		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
1	**Safe Haven**	NA	OC	HC	OC	HC	OC	OC	HC	HC	HC	HC	HC	HC	HC	HC	HC	HC	HC
2	**Control Room**		NA	HC	OC	HC	OC	OC	HC	HC	HC	HC	HC	HC	HC	HC	HC	HC	HC
3	**Generator**			NA	OC	HC	HC	OC	HC	HC	HC	HC	HC	HC	HC	OC	HC	OC	HC
4	**Switchgear**				NA	OC	OC	OC	HC	HC	HC	HC	HC	HC	HC	OC	HC	OC	HC
5	**Emergency Generator**					NA	HC	HC	HC	HC	HC	HC	HC	HC	HC	OC	HC	OC	HC
6	**Communications Equipment Room**						NA	OC	HC	HC	HC	HC	HC	HC	HC	OC	HC	OC	HC
7	**HVAC Fan Room**							NA	HC	HC	HC	HC	HC	HC	HC	OC	HC	OC	HC
8	**Wellheads/ Manifolds**								NA	HC	HC	HC	HC	HC	HC	HC	HC	HC	HC
9	**Separation and Process Equipment**									NA	HC	HC	HC	HC	HC	HC	HC	HC	HC
10	**Platform Utilities**										NA	HC	HC	HC	HC	OC	HC	OC	HC
11	**Compressors**											NA	HC	HC	HC	OC	HC	OC	HC
12	**Drilling**												NA	HC	HC	OC	HC	OC	HC
13	**Shale Shaker/Mud Pits**													NA	HC	OC	HC	OC	HC
14	**Mud Pump**														NA	OC	HC	OC	HC
15	**Workshops**															NA	OC	OC	HC
16	**Laboratory**																NA	OC	HC
17	**Storage Areas (Hazardous)**																	NA	HC
18	**Storage Areas (Non-Hazardous)**																		NA

Legend:

OC–Ordinary Combustible

HC–Hydrocarbon

NA–Not Applicable

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2.6.3. Fireproofing Ratings

Fireproofing ratings, as listed in Table 1, Fireproofing Ratings–Structures and Equipment, shall be assigned based on the fire exposure and the presence of the following elements:

- Critical platform structural members: Columns or beams that, if damaged or weakened by fire either individually or in combination with others, would result in a loss of platform structural integrity.
- Critical escape routes: Ensure that personnel can either retreat to the safe haven or approach abandonment points without impairment. The degree of protection required shall be determined by the hazard assessment.
- Other items shall be fireproofed if the need is identified in the hazard assessment. Mobil shall be consulted on methods to be considered and shall approve the method chosen.

2.7. Offsite Areas

Generally, fireproofing is not required for supporting steel elements located in offsite areas, unless they support high fire potential equipment, are within 9 m (30 ft) of high fire potential equipment or are subject to a flammable liquid spill fire. For example, the support legs for pressure storage spheres and the supporting structure for pressure storage cylinders shall be fireproofed.

2.8. Buildings

Buildings shall be classified for occupancy as specified in the ICBO UBC-1997-LL, NFPA 220 or other codes that supercede fire resistance and/or fire protection requirements. Usually, buildings that do not contain flammable liquids and are equipped with automatic water sprinkler systems need not be fireproofed. Roofs or walls may be considered to limit a fire-exposed area when constructed of fire resistance materials such as:

- Self-supporting masonry walls or reinforced concrete walls
- Masonry walls 200 mm (8 in) or thicker and concrete walls 150 mm (6 in) or thicker on a fireproofed frame
- Gypsum plank, concrete roof or deck on a fireproofed frame

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3. Structures and Equipment–Materials and Application

3.1. General

Concrete and several lightweight products are suitable for the fireproofing of structural steel when installed in accordance with the requirements of this Practice.

The fireproofing material or assembly selected shall be suitable for the ambient conditions of the location(s) where the fireproofing will be applied and permanently located.

3.2. Application

3.2.1. Delivery and Storage

All materials and primer shall be delivered to the job site in factory-sealed containers.

All materials (primers, coatings, solvents, etc.) shall be stored under conditions recommended by the manufacturers. Consult the manufacturers' product data sheets.

3.2.2. Surface Preparation

For all materials, substrate surface preparation is the first step to successful fireproofing. This document addresses substrates that are free of fireproofing or other coating materials. For previously coated or fireproofed substrates, the condition of the substrate, adhesion of coatings and compatibility of materials shall be individually evaluated with the proposed vendor's material specifications.

Before insulation is installed, carbon steel surfaces between 0–93°C (32–200°F) shall be prepared and painted as specified in the fireproofing vendor's specifications.

Surface preparation shall include considerations of substrate, primer and coating. Both fireproofing material manufacturer and primer manufacturer recommendations shall be considered to ensure compatible surface preparation. Refer to the example for mastic fireproofing materials in Table 3.

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Table 3: Example Surface Preparations

Substrate	Condition	Fireproofing Material	Surface Preparation
Steel	Uncoated	Mastic	Degrease using steam, hot water wash or proprietary cleaners. Dry blast to a commercial finish SA 2 or near white SA 2.5 as specified by primer manufacturer. Prime surface before rust bloom occurs. Use an epoxy or inorganic zinc with epoxy tiecoat applied to thickness 50–75 microns as specified by the mastic manufacturer.
Galvanized Steel	New	Mastic	Solvent clean. Dry blast or otherwise mechanically abrade to 25 micron. Apply an epoxy primer to 25 micron thickness as specified by the mastic manufacturer.

3.2.3. Installation

Composition of the various materials shall be considered relative to the safety of personnel involved or in the vicinity of installation activities. Some materials are inherently toxic and/or flammable. Some require flammable solvents during mixing and application. Consult material safety data sheets and application procedures.

Fireproofing materials are typically applied by one of four techniques:

- Formed and poured
- Troweled
- Sprayed
- Mechanically fastened

3.2.3.1. Environmental Conditions

Successful installation of fireproofing material depends on the environmental conditions expected at the site and the ability of the manufacturer's material to be applied under such conditions.

Mobil shall establish environmental conditions (for example, temperature, humidity and wind) under which the material will be applied. Mobil and contractor shall agree that ambient conditions and application techniques are appropriate at the time of installation.

3.2.4. Masking and Cleanup

Prior to spraying fireproofing materials, all structures and components of equipment that are not to be fireproofed shall be masked or otherwise protected against inadvertent overspray.

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Once fireproofing has been applied and has set, masking shall be removed before the overspray fireproofing material cures and makes removal difficult. Care shall be taken not to disturb newly fireproofed substrate. All surplus materials and masking shall be removed, leaving the work area clean.

3.2.5. Weatherproofing

All fireproofing located outdoors shall be sealed by caulking or flashing to prevent moisture from reaching the fireproofed steel surface.

- All coated surfaces shall be examined to identify potential water entrance areas, which shall be sealed with an approved exterior grade caulking material.
- All termination points of the coating shall be built up to drain off water on horizontal shelf areas.
- Special care shall be taken to caulk around water stop protrusions such as brackets, flanges, valves, pipe entrances, stanchions, heavy welded seams and similar welded attachments, and at intersects that interrupt the smooth contour of the surface area.

The final coat of all fireproofing mastics shall be rolled or brushed to provide a smooth surface finish, unless waived by Mobil. The material shall be applied with a sufficient number of coats to prevent running or slumping. Sufficient drying time shall be allowed between coats.

3.3. Concrete

For the purpose of this Practice, 2 inches of concrete shall be considered to provide a one-hour fire resistance rating per UL 1709.

Concrete fireproofing shall meet the requirements of MP 01-P-07 and shall be designed in accordance with the requirements of this Practice.

3.3.1. Formed Concrete

Formed concrete shall consist of surface dry aggregate and cement conforming to ASTM C150 and shall be Type 1 (normal) or Type 1A (air entrained).

Formed concrete mix shall consist of one part cement and two and a half parts each of sand and gravel passing a 9.5 mm ($^3/_8$ in) sieve. The water/cement ratio shall be 0.53 by weight.

3.3.2. Pneumatically Applied Concrete

Pneumatically applied concrete shall conform to ASTM C150, Type 1.

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The concrete shall consist of one part cement to four parts sand. Sufficient water shall be added to hydrate the cement. Water shall not exceed 12 l (3 gal) per bag of cement at the nozzle.

Operating equipment within 15 m (50 ft) of pneumatic concrete application operations shall be covered or otherwise protected from overspray.

3.3.3. Steel Substrate

Prior to installation of concrete, steel substrate shall be free of dirt, grease and loose scale.

3.3.4. Reinforcement

Concrete shall be reinforced by electrically welded wire fabric, 50 x 50 x 2.3 mm (2 x 2 in x 12 U.S. gauge).

- For outdoor use, the wire mesh shall be galvanized.
- Tie wire shall be 1.6 mm (0.063 in) diameter, annealed black iron.
- Reinforcing wire fabric shall be lapped 50 mm (2 in) minimum at joints.
- The reinforcing fabric shall be spaced out from the substrate surface about one-half the fireproofing thickness.

3.3.5. Column Tops

Tops of columns, where water could penetrate between steel and concrete, shall be weatherproofed with a caulking bead or other approved mastic application.

3.4. Lightweight Concrete

- The density required for a particular application shall be as determined by a recognized testing laboratory to achieve the desired fire resistance rating. The vendor shall indicate the fire resistance rating based on the UL 1709 or equivalent high-rise fire test.
- The material shall be capable of withstanding a direct flame impingement at 1100°C (2000°F), thermal shock and high pressure water streams.
- Prior to installation of lightweight concrete, steel substrate shall be free of dirt, grease and loose scale.
- Metal mesh reinforcement shall be provided in accordance with the manufacturer's requirement to meet the specified fire resistance rating.
- The finished lightweight concrete shall be given two coats of a sealer for weather protection. The seal coat shall be equivalent to the concrete manufacturer's

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recommendation for the extreme conditions that may be encountered in the geographical area of structures or equipment.

3.5. Preformed/Inorganic Panels

Pre-formed panels and their attachment system shall pass the UL 1709 or equivalent high-rise fire test for the fire resistance rating required.

The panels shall be attached using only an attachment system with which they were tested.

For exterior applications, selection of a panel/attachment system shall be based on its ability to withstand prevailing weather conditions as well as to provide the required fire resistance.

3.6. Concrete Masonry

- Concrete blocks containing lightweight, expanded, blast-furnace slag as the coarse aggregate may be used to fireproof structural steel and pipe columns.
- The blocks shall provide a one-hour minimum UL 1709 or equivalent high-rise hydrocarbon fire resistance rating.
- Prior to installation of masonry, the steel substrate shall be free of dirt, grease and loose scale.
- Column covers and blocks shall be laid with thin, staggered joints 6.4 mm ($^1/_4$ in) maximum thickness and a fire-resistant mortar.
- The annular space between the column covers or blocks and the steel member shall be filled with a lean cement to prevent moisture or hot gasses from reaching the steel during a fire. A bead of caulking shall be applied at the top of the column for weather protection.
- Masonry brick and mortar providing a UL 1709 or equivalent high rise fire test rating of at least one hour may be used to fireproof vessel skirts.

3.7. Fireproofing Mastics

3.7.1. Application

Fireproofing mastic compounds shall not be installed on surfaces with continuous operating temperatures in excess of the thermal stability level of the material.

Mastic fireproofing material shall be applied by spraying or troweling. Surface preparation for application of a paint primer shall be in accordance with the manufacturer's recommendations.

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3.7.2. Previously Painted Surfaces

For previously painted and/or fireproofed surfaces, the mastic manufacturer shall be consulted to ensure compatibility with the existing surface, proposed paint primer and mastic.

- New galvanized surfaces shall be mechanically abraded to ensure adherence of the prime coating.
- When existing structural steel is being fireproofed, all oil and grease shall be removed by solvent or caustic cleaning.
- All loose paint and scale shall be removed by scraping, wire brushing or blast cleaning.

3.7.3. Spray-On Applications

For spray-on applications, consult the manufacturer on minimum application temperature. Some materials do not flow through the pump and/or sprayer below 4–10°C (40–50°F); some materials do not cure well below -1–4°C (30–40°F).

3.7.4. Mechanical Reinforcement

To ensure proper adherence, mechanical reinforcement shall be provided for mastic materials in accordance with the manufacturer's recommendation and/or application listing.

3.7.5. Surface Finish and Sealant

The final coat of all fireproofing mastics shall be rolled or brushed to provide a smooth surface finish. The material shall be applied with a sufficient number of coats to prevent running or slumping. Sufficient drying time shall be allowed between coats.

Intumescent and subliming mastic coatings shall be sealed for weather protection in accordance with the manufacturer's recommendations for possible extreme conditions that may be encountered in certain geographical areas.

3.7.6. Supervision

Spray-equipment operators responsible for the application of fireproof mastic shall be under the direct supervision of a trained applicator and qualified by the mastic manufacturer in writing. Applicator certificates shall be renewed annually.

The contractor shall supervise the installation to ensure that the thickness and quality of the materials and workmanship provide the level of protection required.

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3.8. Thermal Insulation

3.8.1. Types of Insulation

Insulation used for fireproofing shall be rated for 650°C (1200°F) minimum service (see MP 34-P-10). Insulation shall consist of one of the following types of materials:

1. Calcium silicate, block or preformed
2. Mineral wool block with a minimum density of 192 kg/m^3 (12 lb/ft^3)
3. Perlite, block or preformed
4. Expanded alumina silica fiber blanket with a minimum density of 96 kg/m^3 (6 lb/ft^3)

3.8.2. Vessel Skirts

For vessels with a height (vessel plus skirt) to diameter ratio less than four, insulation may be used for fireproofing vessel skirts. For vessels with a height (vessel plus skirt) to diameter ratio equal to or greater than four, the vessel skirt shall be fireproofed with 50 mm (2 in) of concrete.

When insulation is used to fireproof steel that will be at or below ambient conditions, precaution shall be taken to prevent external corrosion of the steel caused by condensation when the steel is below the atmospheric dew point.

3.8.3. Minimum Thickness

Minimum thickness of insulation for fireproofing shall be 50 mm (2 in).

3.8.4. Surface Preparation

Before insulation is installed, carbon steel surfaces of 0–93°C (32–200°F) shall be prepared and painted in accordance with MP 35-P-01. A vapor barrier shall be provided over the outer layer of the insulation in accordance with MP 34-P-11. Moisture contamination of the insulation shall be avoided to prevent damage to the insulation as a result of steam pressure caused by a fire.

3.8.5. Weatherproofing

Insulation used for fireproofing shall be weatherproofed with either a corrugated or flat stainless steel sheet, 0.25 mm (0.01 in) thick, Type 304, 316, 321 or 0.6 mm (24 U.S. gauge galvanized). Bands and screws used for fastening shall be stainless.

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3.8.6. Aluminum Pipe

When calcium silicate or perlite is used to fireproof aluminum pipe, tubing and conduit in cold service, the aluminum shall be protected by one of the following:

- A coat of vinyl wash primer, or equivalent, 0.13 mm (0.5 mils) dry thickness
- Wrapped with polyethylene sheeting 0.15 mm (0.0006 in) thick to prevent corrosion due to insulation alkalinity

When the insulation manufacturer provides a written guarantee that products will not cause corrosion of aluminum, the primer coat or the polyethylene sheeting may be omitted.

3.9. Magnesium Oxychloride Plasters

Magnesium oxychloride plasters shall not be used for fireproofing.

3.10. Wrap-Type Systems

- Wrap-type systems shall pass the UL 1709 or equivalent high-rise fire test for the fire resistance rating required.
- The systems shall be used in accordance with manufacturer recommendations and shall be attached using only the method with which they were tested.
- The protected surface shall be painted, coated or otherwise protected for the expected environmental exposure unless otherwise indicated by the manufacturer of the system.

4. Instrumentation, Electrical and Valve Operators

4.1. Main Instrument Runs

Main banks of aboveground instrument runs (such as those coming from the control room and supported on process unit pipe racks) that are located inside process unit battery limits and within a fire-exposed envelope shall be fireproofed or protected by one of the methods described in this Section.

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4.1.1. Insulation

Perforated and non-perforated metal instrument trays shall be completely enclosed with 25 mm (1 in) minimum thickness insulating block or board conforming to Section 3.8.1.

- The insulation shall be secured with stainless steel bands and shall be weatherproofed with vinyl-coated galvanized steel sheet subject to Mobil approval. The bands and sheet shall be in conformance with Section 3.8.5.
- The metal jacket shall be secured with stainless steel, sheet metal screws or bands.

4.1.2. Intumescent Mastic

Non-perforated galvanized steel sheet metal trays may be protected by either Method A or Method B.

4.1.2.1. Method A

Non-perforated galvanized sheet metal trays that completely enclose instrument cable and tubing shall be coated on all sides with an approved intumescent mastic 6.4 mm (0.25 in) dry thickness.

- This exterior coating shall be reinforced with wire mesh in accordance with manufacturer's recommendation.
- Prior to application of the mastic, new galvanized trays shall be mechanically abraded by grit blasting or other means to ensure adhesion of the prime coat.
- Abrasion depth shall be 0.13 mm (0.5 mil).

4.1.2.2. Method B

This is the same as Method A except that 25 mm (1 in) thick mineral wool insulating board, with a density of 96–128 kg/m^3 (6–8 lb/ft^3), shall be glued to the bottom of each tray to separate the instrument lines from the sheet metal tray. Also, the outside of the tray shall be coated with an approved intumescent mastic 4.8 mm (0.19 in) dry thickness.

4.1.2.3. Box

For perforated, non-perforated and ladder-type trays, a box with a removable cover shall be fabricated with 1.1 mm (0.044 in) minimum diameter galvanized hardware cloth with 12.5 x 12.5 mm (0.50 x 0.50 in) openings.

- The box shall be lined on all sides with 25 mm (1 in) thick mineral wool insulating board with a density of 96–128 kg/m^3 (6–8 lb/ft^3).

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- The outside of the mesh shall be sprayed with mastic 4.8 mm (0.19 in) dry thickness.
- The entire assembly shall be prefabricated, sprayed and field installed.
- Prior to installation, the instrument cable or tubing shall be wrapped with 0.025 mm (1 mil) of aluminum foil.

4.1.3. Subliming Mastic

Non-perforated galvanized steel sheet metal trays that completely enclose instrument tubing shall be coated with mastic for a UL 1709, 15-minute test rating or equivalent.

- Weather-protective top coatings shall be applied as specified by the vendor.
- Prior to application of the subliming mastic, the galvanized steel sheet metal shall be primed as required by the vendor of the mastic.
- The mastic coating shall be reinforced on all four corners of the cable tray by application of a 140 mm (5.5 in) wide strip of open-mesh fiberglass cloth between coats of mastic.

4.1.4. Mineral Wool/Cement Board

Perforated and non-perforated sheet metal and ladder-type cable trays shall be completely enclosed with 25 mm (1 in) minimum thickness mineral wool/cement board panels or equivalent. The panels shall be secured with stainless steel screws and/or stainless steel bands 19 mm (0.75 in) wide by 0.5 mm (0.02 in) thick, located no more than 450 mm (18 in) apart.

In freezing climates, the fireproofing panels shall be given a weatherproof coat of paint. The structural strength of the metal cable tray shall be adequate to support the weight of the fireproofing.

4.1.5. Prefabricated Fireproof Wrap-Type Systems

Prefabricated fireproof wrap-type systems that meet the UL 1709 high-rise hydrocarbon fire resistance rating (or equivalent) for 15 minutes protection may be considered for use on instrument runs. These systems shall be composed of high-temperature insulating material that is wrapped around the instrument runs and is readily removable for maintenance activities.

4.1.6. MI Electric Cable

When approved by Mobil, mineral insulated (MI) instrument cable may be used in lieu of fireproofing. Magnesium oxide insulation shall be stable at 1650°C (3000°F). An outside metal sheath of stainless steel or high temperature alloy shall be provided. High-pressure, liquid-tight fittings shall be used. Supports for MI cable shall be steel.

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4.1.7. Water Sprays

When approved by Mobil, open and closed instrument trays shall be protected by automatically activated fixed water sprays in accordance with NFPA 15, MP 70-P-01 and MP 70-P-07.

4.2. Tubing, Conduit and Valve Operators

4.2.1. Fireproofing Exceptions

Instrument air tubing, electrical cable or conduit and valve operators designed to function during a fire (such as depressuring valves and remote operated emergency and shutdown valves) shall be fireproofed as discussed herein. These cables/tubing need not be fireproofed under the following conditions:

- The affected portion of the system consists entirely of stainless steel tubing (Types 304, 310, 316)
- Where failure of the cabling/tubing will result in the controlled device going to its desired failure position in all situations

4.2.2. Tubing and Conduit Protection

Cable, conduit and tubing shall be fireproofed by one of the following methods:

- Apply preformed pipe insulation of 50 mm (2 in) minimum thickness for conduit or tubing NPS 2 (NPS = nominal pipe size, inches) or more in outside diameter; use 40 mm (1.5 in) thickness for conduit or tubing under NPS 2 in outside diameter. Insulating materials and jacketing shall be in accordance with Section 3.8.
- Cover conduit or tubing with a prefabricated wrap-type system approved by Mobil to provide the required protection.

4.2.3. Motor Protection

The motor of remote-controlled, electric motor operated valves shall be fireproofed by one of the following methods. The contractor shall ensure that the valve operator will not overheat when insulated because of the absence of ventilation.

- Cover the motor with 50 mm (2 in) of preformed pipe insulation or box-in with 50 mm of insulating block conforming to Section 3.8.1. When a thermal overload cutoff for the motor is installed on the motor windings, it shall be disconnected. Then another overload protection shall be provided at the motor starter (such protection may be eliminated if approved by Mobil). The handwheel and engaging lever shall not be fireproofed; they shall be accessible from outside the fireproofing.

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- Coat the motor enclosure with an intumescent mastic fireproofing as described in Section 3.7. The coating shall be similar to the "K-Mass" fireproofing system by Thermal Designs.
- Cover the motor operator with a prefabricated wrap-type system as described in Section 3.10. The system chosen shall be easily removable for all maintenance activities.

4.2.4. Solenoid Protection

The solenoid of solenoid-operated valves shall be fireproofed by one of the following methods:

- Cover the solenoid with 50 mm (2 in) of insulation conforming to Section 3.8.1. All fireproofing designs shall be reviewed with Mobil to ensure that the valve operator will not overheat (with insulation) because of the absence of ventilation.
- Coat the solenoid with an intumescent mastic fireproofing as described in Section 3.7. The coating shall be similar to the "K-Mass" fireproofing system by Thermal Designs.
- Cover the solenoid with prefabricated wrap-type system as described in Section 3.10.

4.2.5. Diaphragm Housing Protection

The diaphragm housing of diaphragm-operated valves shall be fireproofed by one of the following:

- Coat the diaphragm with an intumescent mastic fireproofing as described in Section 3.7. The coating shall be similar to the "K-Mass" fireproofing system by Thermal Designs.
- Cover with 50 mm (2 in) of preformed pipe insulation or boxed in with 50 mm of block insulation conforming to Section 3.8.1.

4.3. Power Cables

Critical power cables are those that transmit power to equipment whose function is vital to ensure safe shut down and depressurization. These cables shall also be considered critical if necessary for the continued operation of the communications system. They shall be fireproofed in a manner similar to critical instrument cabling/tubing. The cables need not be fireproofed if:

- The cabling is mineral insulated (MI) instrument cable approved by Mobil.
- The failure of the cabling will result in the equipment being supplied with power going to its desired failure position in all situations.

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5. Quality Control

A quality control program shall be developed prior to installation of fireproofing material. The program shall be approved by Mobil and shall include all aspects of the installation from base preparation, application controls and inspection/correction procedures to ensure integrity. Manufacturer and vendor recommendations shall be incorporated where appropriate.

5.1. Monitoring and Inspection

- Prior to fireproofing, the applicator shall prepare a representative sample of the fireproofing to be used as a comparison for inspecting surface finish.
- During application, all fireproofing shall be visually inspected for shrinkage cracks, mechanical damage and integrity of caulking and spackling. These deficiencies shall be corrected in accordance with the vendor's recommended procedure.
- The applicator shall continuously measure wet thickness of gunned, sprayed and troweled fireproofing, using a probe gauge. Dry thickness shall be measured by bore samples and a magnetic gauge.
- Random bore samples of gunned and troweled, dense and lightweight concrete shall be made at locations selected by Mobil. Initial bore samples shall be made on the basis of one per each 5 m^2 (50 ft^2). If the samples meet job requirements, sampling may be increased to one per 10 m^2 (100 ft^2) subject to Mobil approval. Repairs shall be made to bored areas using the vendor's recommended procedure.
- Qualified Mobil personnel shall monitor material mixing, density, preparation of substrate, applied thickness, surface finish and surface coatings.

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Appendix A: Fire Resistance Ratings

The following table summarizes the fire resistance ratings referred to in this MEP:

Table A–1: Fire Resistance Ratings

Rating	Normal Configuration	Test Environmental Temperature	Criteria to be Met	Test Type
ASTM E119 REV A Column Test (Note 1)	W10 x 49, column at least 8 ft high	Follows ASTM E119 REV A time/temperature curve	Protected steel temperature shall not exceed 1000°F (538°C)	Cellulosic fire simulation, designed for commercial buildings Gas-fired furnace
UL 1709 (Note 2)	W10 x 49, column 9 ft high	2000°F (1093°C)	Protected steel temperature shall not exceed 1000°F (538°C)	High intensity or high rise fire curve Gas fired furnace
A-30 (Note 1)	Bulkhead or deck section 9 m^2, usually 4.8 mm or greater steel thickness	Follows ASTM E119 REV A time/temperature curve (or equivalent)	Protected steel temperature not to exceed a rise of 250°F (139°C) for 30 minutes No passage of smoke or flames and maintain structural integrity for 60 minutes	Cellulosic fire simulation, designed for commercial buildings Gas fired furnace
A-60 (Note 1)	Bulkhead or deck section 9 m^2, usually 4.8 mm or greater steel thickness	Follows ASTM E119 REV A time/temperature curve (or equivalent	Protected steel temperature not to exceed a rise of 250°F (139°C) for 60 minutes No passage of smoke or flames and maintain structural integrity for 60 minutes	Cellulosic fire simulation, designed for commercial buildings Gas fired furnace
A-120 (Note 1)	Bulkhead or deck section 9 m^2, usually 4.8 mm or greater steel thickness	Follows ASTM E119 REV A time/temperature curve (or equivalent)	Protected steel temperature not to exceed a rise of 250°F (139°C) for 120 minutes No passage of smoke or flames and maintain structural integrity for 120 minutes	Cellulosic fire simulation, designed for commercial buildings Gas fired furnace

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Rating	Normal Configuration	Test Environmental Temperature	Criteria to be Met	Test Type
H-60 (60 minute) (Note 1)	Bulkhead or Deck section 9 m^2, usually 4.8 mm or greater steel thickness	2000°F (1093°C)	Protected steel temperature not to exceed a rise of 250°F (139°C) for 60 minutes No passage of smoke or flames and maintain structural integrity for 120 minutes	UL 1709 or Norwegian Petroleum Directorate high intensity or high rise fire curve Gas fired furnace
H-120 (120 minute) (Note 1)	Bulkhead or Deck section 9 m^2, usually 4.8 mm or greater steel thickness	2000°F (1093°C)	Protected steel temperature not to exceed a rise of 250°F (139°C) for 120 minutes No passage of smoke or flames and maintain structural integrity for 120 minutes	UL 1709 or Norwegian Petroleum Directorate high intensity or high rise fire curve Gas fired furnace
H-0 (Note 1)	Bulkhead or Deck section 9 m^2, usually 4.8 mm or greater steel thickness	2000°F (1093°C)	No passage of smoke or flames and maintain structural integrity for 120 minutes	UL 1709 or Norwegian Petroleum Directorate high intensity or high rise fire curve Gas fired furnace

NOTES:

1. For offshore facilities
2. For onshore facilities

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Appendix B: Suggested Fireproofing Materials

Table B–1: Fireproofing Materials

Product Name	Required Thickness				Approval Method	Date Added
	15 Minute Rating	30 Minute Rating	1 Hour Rating	2 Hour Rating		
3M Interam E5-3A & 4A	0.40 in (1 wrap E-5A-4)	0.30 in (1 wrap E-5A-3)	0.60 in (2 wraps E-5A-3)		Mobil Test Facility	Jul-91
Aerex Panels			1.0 in	1.5 in	UL 1709	Jul-91
AP Green Inswool (structural steel only, not cable trays)			3 in		Mobil Test Facility	Oct-91
Albi Clad–800		0.2 in M	0.32 in M		Mobil Test Facility	Jul-91
Albi Clad–800			0.25 in	0.51 in F	UL 1709	Jul-91
Carboline Pyrocrete 240		0.5 in M	1.00 in M		Mobil Test Facility	Jul-91
Carboline Pyrocrete 240			0.81 in M	1.38 in M	UL 1709	Jul-91
Carboline Pyrocrete 241		0.5 in M	1.00 in M		Mobil Test Facility	Jul-91
Carboline Pyrocrete 241			0.69 in M	1.13 in M	UL 1709	Jul-91
Carboline Pyrocrete 241				0.38 in M	FM	Jul-91
Carboline Pyrocrete 241			0.94 in M	1.25 in M	FIRTO (H60 & H120)	Jul-91
Carboline Pyrocrete 241			0.81 in M	1.25 in M	DNV (H60 & H120)	Jul-91
Carboline Pyrocrete 241			0.94 in M	1.25 in M	LRS (H60 & H120)	Jul-91
Carboline Pitt –Char XP		0.2 in M	0.40 in M		Mobil Test Facility	Jul-91

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Product Name	Required Thickness				Approval Method	Date Added
	15 Minute Rating	30 Minute Rating	1 Hour Rating	2 Hour Rating		
Carboline Pitt –Char XP			0.28 in F	0.52 in F	UL 1709	Jul-91
Carboline Pitt –Char XP				NP	2 hr Jet Fire Test by SRI	Jul-91
Darchem Darmatt Blanket for cable trays	4 layers, 4 lb/ft^3				Mobil Test Facility	Jul-91
Darchem Darmatt Blanket for cable trays	NP	NP	NP	NP	DNV & LRS	Jul-91
Darchem Darmatt J120 Blanket				3 layers of 1 in thick, 6 lb/ft^3	2 hr Jet Fire Tests by SNBL & HSL and approved by DNV & LRS	Aug-97
Mandoval Mandolite 550		0.5 in M	0.9 in M		Mobil Test Facility	Jul-91
Mandoval Mandolite 550			1.34 in M	1.73 in M	DNV & LRS (H60 & H120)	Jul-91
Mandoval Mandolite 990			0.51 in M	0.71 in M	DNV & LRS (H60 & H120)	Aug-95
Mandoval Mandolite 990				0.67 in	2 hr Jet Fire Tests by SNBL & HSL	Aug-95
Mandoval Fendolite MII		0.5 in M	1.0 in M		Mobil Test Facility	Jul-91
Mandoval Fendolite MII			1.0 in M	1.44 in M	UL 1709	Jul-91
Mandoval Fendolite MII				NP	FM	Jul-91
Pabco Super Firetemp M		0.75 in	1.25 in		UL 1709	Jul-91
Pittsburg Corning Foamglas Super K or T-4 in Europe (API 520/1 factor = 0.3, SS jacketing > 0.7 mm thickness)				Two 3 in layers each w/ SS bands	UL 1709 MODIFIED	May-95

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Product Name	Required Thickness				Approval Method	Date Added
	15 Minute Rating	30 Minute Rating	1 Hour Rating	2 Hour Rating		
Pittsburg Corning Foamglas Super K or T-4 in Europe (API 520/1 factor = 0.3, SS jacketing > 0.7 mm thickness)			4.0 in		UL 1709 per other oil company specs	May-95
Pittsburg Corning Foamglas with Interam E-5A Mat			3.0 in			Jul-91
Pyrotenax MI Cables	Alloy 825 Ni Clad	Alloy 825 Ni Clad			Mobil Test Facility	Jul-91
Superior Energies Temp Set Blanket for cable trays	2.0 in (Cable trays only)				Mobil Test Facility	Jul-91
Textron Coroc II Panels			2.0 in		UL 1709	Jul-91
Textron Charcast Panel System				NP	LRS (H120)	Sep-97
Textron Chartek IV			0.27 in M	0.55 in M	UL 1709	Apr-96
Textron Chartek IV			0.39 in M	0.59 in M	DNV & LRS (H60 & H120, Bulkheads)	Apr-96
Textron Chartek IV			0.43 in M	0.71 in M	DNV & LRS (H60 & H120, Decks)	Apr-96
Textron Chartek VII			0.16 in M	0.35 in M	Jet Fire Tests by SNBL	Apr-96
Textron Chartek VII			0.39 in M	0.51 in M	LRS (H60 & H120, Bulkheads)	Sep-97
Textron Chartek VII			0.35 in M	0.51 in M	DNV (H60 & H120, Bulkheads)	Sep-97
Textron Chartek VII			0.39 in M	0.59 in M	LRS (H60 & H120, Decks)	Sep-97
Textron Chartek VII			0.35 in M	0.59 in M	DNV (H60 & H120, Decks)	Sep-97
Thermal Ceramics Firemaster Blanket,	1.0 in blanket	1.0 in lb/ft^3 blanket	1.5 in 8 lb/ft^3 blanket		Mobil Test Facility	Jul-91

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Product Name	Required Thickness				Approval Method	Date Added
	15 Minute Rating	30 Minute Rating	1 Hour Rating	2 Hour Rating		
w/ SS Encapsulation	covered by 0.5 in SS encap. 8 lb/ft^3 blanket					
Thermal Designs, K-Mass molded electrical boxes and MOV actuators	0.5 in				Mobil Test Facility	Jul-92
Thermal Sciences Thermo-lag 440		0.20 in M	0.30 in M		Mobil Test Facility	Jul-91
Thermal Sciences Thermo-lag 440			0.28 in F	0.67 in F	UL 1709	Jul-91
Thermal Sciences Thermo-lag 440		0.20 in F	0.35 in F	0.63 in F	DNV & LRS (H60 & H120 w/ hp/A Steel Size of 150)	Jul-91
Thermal Sciences Thermo-lag 440					90 minute pool fire w/ 0.24 in thickness tested by BAM	Jul-91
Thermal Sciences Thermo-lag 440				NP	2 hr Jet Fire Test by SL	Jul-91
Thermal Sciences Thermo-lag 2000			0.22 in F	0.44 in F	UL 1709	Nov-95
Thermal Sciences Thermo-lag 2000		0.12 in F	0.28 in F	0.59 in F	DNV & LRS (H60 & H120 w/ hp/A Steel Size of 150)	Nov-95
Thermal Sciences Thermo-lag 2000				NP	2 hr Jet Fire Tests witnessed by DNV & LRS	Nov-95
Unipad Blanket for cable trays	UP 15/18/24	UP 34			UL 1709 conducted by Omega Point Labs	Feb-96
Whittaker SI 2400 Cables	NA				Mobil Test Facility	Jul-91
Whittaker SI 2400 Cables				NA	UL 1709 & NPD by SRI (3 hrs at 2100°F)	Jul-91

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NP	Not provided
NA	Not applicable
M	Designates materials that require installation with wire mesh reinforcement
F	Designates materials that require installation with fiberglass ribbon reinforcement
LRS	Lloyd's Register of Shipping
DNV	Det Norske Veritas
NPD	Norwegian Petroleum Directorate
SNBL	Sintef NBL, the Norwegian Fire Research Institute
HSL	Health & Safety Laboratory, UK
UL 1709	Underwriters Laboratory High Rise Fire Test (W10 x 49 Column 9 ft High)
FM	Tested and listed by Factory Mutual for LPG vessels
SL	Shell Ltd. UK Sponsored Test at British Gas Test Facility (UK)
BAM	Bundesanstalt Fur Materialprufung (Germany)
SRI	Southwest Research Institute
FIRTO	Fire Ensurers' Research and Testing Organization–London (Loss Prevention Council)
H-60	1 Hour High Rise Fire Test (Offshore Facilities–Bulkheads/Decks)
H-120	2 Hour High Rise Fire Test (Offshore Facilities–Bulkheads/Decks)

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Painting - Internal Coatings - Tanks, Vessels, Piping and Tubulars

MP 35-P-81

July 1998

Scope

This Mobil Engineering Practice (MEP) provides the requirements for the preparation and coating of internal surfaces of tanks, vessels, piping and tubulars.

Version 0

Table of Contents

Scope **1**

Table of Tables **5**

1. References **6**

1.1. MEPS–Mobil Engineering Practices 6

1.2. Mobil Data Sheets 6

1.3. API–American Petroleum Institute 6

1.4. NACE–National Association of Corrosion Engineers 7

1.5. SIS–Swedish Standards Institute 7

1.6. SSPC–Steel Structures Painting Council 7

2. General **7**

2.1. Materials/Labor 7

2.2. Internal Coatings 8

2.3. Inspection/Warranties 8

3. Coatings Index **8**

3.1. Storage Tanks 9

3.2. Vessels 11

3.3. Piping and Tubulars 12

4. Safety **12**

4.1. Work Permit 12

4.2. Spraying Precautions 12

5. Environmental Requirements **13**

6. Quality Assurance and Quality Control **13**

6.1. Mobil Inspection 13

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6.2. Defects 14
6.3. Minimum Requirements 14
6.4. Test Equipment 14
6.5. Coatings 14
6.6. Mechanical Damage Prevention 15
6.7. Shipping 15
7. Surface Preparation 15
7.1. Surface Preparation 15
7.2. White Metal Blast Cleaning 16
8. Coating Application General Requirements 17
8.1. Coating Methods 17
8.2. Chemically Cured Coatings 18
8.3. First Coat 18
8.4. Recoating 19
8.5. Finished Applications/Repairs 19
9. Special Notes on Surface Preparation and Coating Application 20
9.1. Shop-Applied Coatings 20
9.2. Field-Applied Coatings 20
10. Types of Coatings 20
10.1. Non-Reinforced Thin-Film Coatings 21
10.2. Glass Flake Reinforced Coatings 21
10.3. Reinforced Thick-Film Coatings 21
10.4. Cement Linings 21
Appendix: Seam Sealing of Riveted or Bolted Tanks 22
1. General 22

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2. Sealing of Seams 22

2.1. Sealing Procedure 22

2.2. Sealing Methods 23

2.3. Sealing Requirements 23

2.4. Materials 23

2.5. Surface Preparation 24

2.6. Application of Seal Coat 24

2.7. Finish Coats–External Surfaces 25

3. Coating Index 25

4. Inspection 25

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Table of Tables

Table 1: Suggested Vendors 8

Table 2: Acceptability of Systems 9

Table 3: Coating Selection Guide 9

Table 4: Typical Coating Systems (Customary Units) 10

Table 5: Typical Coating Systems (Metric Units) 11

Table A–1: Index of Coating Materials 25

1. References

The following publications form a part of this Practice. Unless otherwise specified herein, use the latest edition.

1.1. MEPS–Mobil Engineering Practices

MP 35-P-01	Painting - General Requirements
MP 20-P-14	Pipeline Corrosion Protection
MP 56-P-02	Cathodic Protection for Tank Bottoms & Underground Piping

1.2. Mobil Data Sheets

Mobil Data Sheets	Mobil Data Sheet Home Page
T3581C01	Painting - Internal Coatings - Tanks, Vessels, Piping & Tubulars - Summary of Structure Paint - Custmary Units
T3581C02	Painting - Internal Coatings - Tanks, Vessels, Piping & Tubulars - Hazardous Waste Generation - Customary Units
T3581M01	Painting - Internal Coatings - Tanks, Vessels, Piping & Tubulars - Summary of Structure Paint - Metric Units
T3581M02	Painting - Internal Coatings - Tanks, Vessels, Piping & Tubulars - Hazardous Waste Generation - Metric Units
D3581C01	Painting - Internal Coatings - Tanks, Vessels, Piping & Tubulars - Documentation Requirements Sheet
I3581C01	Painting - Internal Coatings - Tanks, Vessels, Piping & Tubulars - Inspection & Testing Requirements Sheet

1.3. API–American Petroleum Institute

API STD 653	Tank Inspection, Repair, Alteration, and Reconstruction Second Edition; Errata February 1996; Errata May 1996; Follow Up to Errata May 1996; Addendum 1-December 1996

1.4. NACE–National Association of Corrosion Engineers

NACE 37523	NACE Corrosion Engineer's Reference Book, 2nd Edition

1.5. SIS–Swedish Standards Institute

SIS 055900	Pictorial Surface Preparation Standard for Painting Steel Surfaces

1.6. SSPC–Steel Structures Painting Council

SSPC 93-05	Steel Structures Painting Manual, Volume 1, Good Painting Practice
SSPC 95-01	Steel Structures Painting Manual, Volume 2, Systems and Specifications
SSPC SP 1	Solvent Cleaning (Steel Structures Painting Manual, Ch 2 - Surface Preparation Specs.)
SSPC SP 5	Joint Surface Preparation Standard White Metal Blast Cleaning (NACE No. 1: 1994) (Steel Structures Painting Manual, Ch 2 - Surface Preparation Specs.)
SSPC VIS 1	Visual Standard for Abrasive Blast Cleaning Steel (Standard Reference Photographs) (Steel Structures Painting Manual, Ch 2 - Surface Preparation Specs.)

2. General

The preparations and coating of internal surfaces of tanks, vessels, piping and tubulars shall be in accordance with requirements of this MEP, unless superceded by more stringent local regulations.

- The contractor's coating supervisor shall be familiar with the salient requirements of this Practice and all other information significant to the work to be done.
- It is not possible to describe the coating requirements for every component that might be encountered. Where requirements beyond these described in this MEP are encountered, the contractor shall request Mobil recommendations in a timely manner.

2.1. Materials/Labor

- Only coating materials approved by Mobil shall be used. These materials shall be delivered to the job site in sealed and labeled containers. They shall be stored in a

location that is protected from the elements, per the manufacturer's recommendations, in well ventilated areas, free from excessive heat, open flame or other sources of ignition. Coating materials susceptible to freezing shall be transported and stored in a heated area.

- Unless otherwise specified, the contractor shall furnish all labor, supervision, Mobil-approved coating materials and tools and equipment necessary to perform the surface preparation and painting defined in this MEP.

2.2. Internal Coatings

It may or may not be necessary to apply a coating to vessel or tank internals. These details shall be agreed upon prior to bidding a contract. Examples of the surfaces that may need coating are anode support bars, treater fire tubes support, baffles, defusers, heat coil supports, etc.

2.3. Inspection/Warranties

- All work done by the contractor shall be subject to inspection by Mobil. The contractor shall correct, at no cost to Mobil, all work not conforming to this MEP.
- The contractor and/or coating manufacturers shall warranty, in writing, all materials and workmanship. This is required by D3581C01 of the Mobil Data Sheets.

3. Coatings Index

This section discusses the various surfaces or equipment that shall be coated. Reference to the appropriate coating tables is cited. A list of suggested coating material vendors is also included (refer to Table 1).

Table 1: Suggested Vendors

Jotun	
Ceilcote	For glass flake reinforced coatings
Sigma	
Hempel	
Valspar	
International	
Shaw or Permian	For cement coatings

3.1. Storage Tanks

Internal surfaces of storage tanks can be coated with either thin-film or thick-film materials, as shown in Table 2. The thick-film materials can be applied either reinforced or unreinforced. Coatings for storage tanks are shown in Table 3.

In storage tanks where water bottoms are expected, sacrificial or impressed current internal cathodic protection systems can be used for additional corrosion protection in conjunction with a coating. Refer to MP 56-P-02.

A seam sealing material applied prior to lining application for riveted or bolted tanks is normally required. The Appendix of this MEP covers this procedure.

Table 2: Acceptability of Systems

Surface to be Coated	Non-reinforced Thin Film Coatings	Glass Flake Reinforced Coatings	Thick Film Reinforced Coatings	Cement
Tanks	Yes	Yes	Yes	No
Vessels	Yes	Yes	No	No
Pipelines	Yes	Yes	No	Yes
Tubulars	Yes	No	No	Yes

NOTES TO TABLE 2:

1. The coating systems in this guideline are general. Manufacturers of the particular coating to be used shall be required to confirm chemical compatibility.
2. Details on particular coating systems are included in Tables 3, 4 and 5.
3. For high abrasion service, thick-film reinforced coatings can be considered.

Table 3: Coating Selection Guide

Service	Tanks	Vessels	Pipeline	Tubulars
	Coating System Numbers (from Tables 4 and 5)			
Potable H_2O	1, 2, 5, 6, 7, 8, 9	1, 2	1, 2, 4, 5, 9, 10	1, 2, 4, 9, 10
Utility H_2O	1, 2, 3, 5, 6, 7, 8, 9	1, 2, 3, 5	1, 2, 4, 5, 9, 10	--
Waste H_2O	1, 2, 3, 5, 6, 7, 8, 9	1, 2, 3, 5	1, 2, 4, 5, 9, 10	--

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Service	Tanks	Vessels	Pipeline	Tubulars
	Coating System Numbers (from Tables 4 and 5)			
Demineralized H_2O	1	1	1, 10	--
Brines (in field)	1, 2, 5, 6, 7, 8	1, 2, 5	1, 2, 4, 5, 9, 10	1, 2, 4, 9, 10
Multiphase (sweet and sour)	1, 2, 5, 6, 7, 8	1, 2, 5	1, 2, 4, 5, 10	1, 2, 4, 10
Abrasive (including kill fluid)	5, 6, 7	5	9	--
Fuels (low aromatic)	1, 2, 5, 6, 7, 8	--	--	--
Fuels (high aromatic)	5, 6, 7	--	--	--
Alcohols	1, 5, 6, 7	--	--	--
Friction Control	--	--	1, 2, 4, 10	--
Wax Control	--	--	1, 2, 4, 10	1, 2

NOTE TO TABLE 3: The actual choice of possible products shall be based on specific operating conditions, economics, availability of products, qualified applicator among other factors.

Table 4: Typical Coating Systems (Customary Units)

No.	System	Typical Total D.F.T. (mils)	Temperature Limits (°F)	Pressure Limitations (psig)
1.	Epoxy Phenolic	10–20	180–220	None
2.	Epoxy	10–20	140–160	None
3.	Coal Tar Epoxy	12–16	120–150	< 200
4.	Fusion Bond Epoxy	15–40	180–200	None
5.	Glass Flake Reinforced	30–40	150	<200
6.	Vinyl Ester Reinforced	50–110	180–200	Atmospheric
7.	Polyester Reinforced	50–110	120–140	Atmospheric
8.	Epoxy Reinforced	50–110	140–160	Atmospheric

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No.	System	Typical Total D.F.T. (mils)	Temperature Limits (°F)	Pressure Limitations (psig)
9.	Cement	250 min	150–180	None
10.	Baked-on Phenolic	10–14	220–250	None

Table 5: Typical Coating Systems (Metric Units)

No.	System	Typical Total D.F.T. (microns)	Temperature Limits (°C)	Pressure Limitations (kPag)
1.	Epoxy Phenolic	250–500	82–100	None
2.	Epoxy	250–500	60–71	None
3.	Coal Tar Epoxy	300–400	49–65	< 1380
4.	Fusion Bond Epoxy	380–1000	82–93	None
5.	Glass Flake Reinforced	750–1000	65	<1380
6.	Vinyl Ester Reinforced	1270–2800	82–93	Atmospheric
7.	Polyester Reinforced	1270–2800	49–60	Atmospheric
8.	Epoxy Reinforced	1270–2800	60 -71	Atmospheric
9.	Cement	6350 min	65–82	None
10.	Baked-on Phenolic	250–350	100–121	None

3.2. Vessels

Generally only thin-film and glass flake reinforced coatings are used in vessels as shown in Table 2. However, thick-film materials can be considered when high abrasion is expected. Coatings for vessels are included in Table 3.

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3.3. Piping and Tubulars

Internal surfaces of piping and tubulars can be coated with thin-film material or cement lining as shown in Table 2. The coatings for piping and tubulars are included in Table 3.

4. Safety

4.1. Work Permit

The contractor shall not start daily work until a work permit has been obtained from Mobil.

- Mobil's work permit covers the entry of the contractor's employees and equipment into the area adjacent to the equipment or facility to be coated, as well as in the immediate area.
- Only Mobil-approved explosion-proof cable, connectors and lights shall be used during the coating operations.
- The contractor shall ascertain that all pertinent and mandatory safety tests have been made. Tests for oxygen sufficiency, hydrogen sulfide (H_2S), carbon monoxide (CO), carbon dioxide (CO_2), explosive mixtures and toxic chemicals may be required.
- Safety conditions, as required by the Occupational Safety and Health Act (OSHA) or other governing bodies as well as those that the work contract may specify, shall be met. Hot work shall not be permitted without a specific permit from Mobil. The granting of work permits shall in no way relieve the contractor, his employees, agents or assignees from responsibility for safe operating procedures.

4.2. Spraying Precautions

Particular care shall be exercised when working in close or confined spaces, especially when spraying. The maximum allowable concentration of solvent in the air shall not be exceeded unless NIOSH (National Institute of Occupational Safety and Health) approved fresh air masks, or their equivalent, are supplied to workers.

When volatile solvents are flammable, the concentration in air shall be kept below 25 percent of the lower explosive limit (LEL) by adequate exhaust or ventilation facilities.

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5. Environmental Requirements

This Section emphasizes waste minimization and hazardous material/waste handling.

- The contractor shall recognize Mobil's commitment to preserving the environment and shall comply with local codes and standards for transporting, storing and disposing of hazardous materials and hazardous wastes.
- Mobil encourages the contractor to recycle all hazardous materials used in connection with the work.
  - The contractor shall notify Mobil, prior to initiation of the job, of the estimated volume and type of hazardous waste to be generated as well as the procedures to be used to accumulate hazardous waste on the job site. The form titled "Hazardous Waste Generation," listed on D3581C01 of the Mobil Data Sheets, shall be used for this purpose.
  - Upon completion of the work, the contractor shall notify Mobil of the volume and type of hazardous waste generated, if any. The Hazardous Waste Generation form shall be used for this purpose.
  - Mobil shall be responsible for the handling and disposal of hazardous waste generated at Mobil-operated locations. The contractor shall deliver hazardous waste and non-recyclable waste hazardous material generated while performing work at Mobil-operated locations to sites designated on D3581C01 of the Mobil Data Sheets.
- Upon completion of the work, all non-hazardous wastes such as empty paint cans, cloths, blasting abrasive, equipment, etc. shall be removed by the contractor from the work site and disposed of properly.

6. Quality Assurance and Quality Control

The contractor shall have a functioning Quality Assurance Program and/or Standard Operating Procedure that controls the application, inspection and testing of the coating operations, as required by D3581C01 of the Mobil Data Sheets.

- The contractor shall submit in writing the full details of all inspection and quality control procedures to be used, including a description of inspection equipment proposed to Mobil for approval.

6.1. Mobil Inspection

- All work and materials applied shall be made available for Mobil inspection. Every aspect of the work shall be readily accessible to the inspector. The contractor shall

inform the inspector prior to the relocation of scaffolding and rigging, so that inspections can be accomplished without rerigging.

- Mobil shall have the right to reject any or all equipment, materials or work that does not conform to Mobil's specification. The contractor shall correct, at no cost to Mobil, all work not conforming to this MEP.

6.2. Defects

The contractor shall be responsible for the inspection of all surfaces after cleaning. The contractor shall notify Mobil of pre-existing defects, improper material or workmanship, or other conditions that will affect the satisfactory performance and permanence of work.

Where such defects have been pointed out, no painting shall be started until all such faulty conditions have been corrected or until a written agreement has been made with Mobil regarding any subsequent defects that may develop because of the conditions noted.

6.3. Minimum Requirements

The contractor's quality control shall ensure, as a minimum, the inspection and recording of information and data contained on D3581C01 of the Mobil Data Sheets. The I3581C01 of the Mobil Data Sheets shall be used as the basis of defining Mobil requirements for witnessing the contractor's testing and documentation requirements.

6.4. Test Equipment

The contractor shall provide and maintain (in good working order at the work site) all necessary test equipment, such as dry-film thickness gauges, to enable test requirements of D3581C01 and I3581C01 of the Mobil Data Sheets to be met.

6.5. Coatings

- Coatings and linings shall be 100 percent holiday tested by the contractor and defects repaired prior to advising Mobil that the work is ready for inspection.
- The coating contractor shall supply a steel test plate, 127 x 127 x 6.4 mm (5 x 5 x $^1/_4$ in), that shall be blasted and coated within the same application parameters as the main job.
  - It is recommended that the Mobil site engineer retain the test panel until at least the first interval inspection of the coating.
  - The first coat shall be applied to the test plate at the same time as the first application to the substrate, and likewise for second and third applications.

6.6. Mechanical Damage Prevention

Internal coatings are susceptible to mechanical damage. Precautions shall be exercised during inspection and/or work in the particular tank or vessel to prevent mechanical damage from occurring. Necessary steps and precautions are:

- Indoor/outdoor carpeting or equivalent (not canvas or cardboard) shall be used to cover the complete floor area and manway areas, where most coating damage occurs.
- Ladders shall have protective rubber on both ends.
- Soft-soled shoes covered with paper "booties" shall be worn.
- Care shall be taken not to track in gravel or other hard foreign objects into the tank or vessel.

6.7. Shipping

- Precautions shall be observed during shipping of internally coated tanks, vessels, piping and tubulars, to avoid coating damage. Mobil shall approve shipping procedures in accordance with D3581C01 of the Mobil Data Sheets.
- For tanks and vessels that have been shipped to their installation site, reinspection shall be necessary to confirm that no coating damage occurred during shipment. The reinspection shall consist of visual examinations, holiday tests and any other inspection procedure deemed necessary.

7. Surface Preparation

Prior to coating, all surfaces shall be thoroughly cleaned of any material that will be conducive to premature failure of the coating. All weld spatter shall be cleaned from substrates. The method of surface preparation used shall be compatible with the coating system.

For surface preparation procedures and requirements, SSPC 93-05 (Vol 1), SSPC 95-01 (Vol 2) or Swedish Standard SIS 055900 shall be used as a reference.

7.1. Surface Preparation

All surface preparation for internal coatings shall be conducted to a white metal blast standard.

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7.2. White Metal Blast Cleaning

White Metal Blast, SSPC SP 5: After blasting, the surface shall be free of dirt, mill scale, rust, corrosion products, oxides, paint or other foreign matter. The surface shall have a gray-white, uniform metallic color, slightly roughened (profile pattern) to form an increased bonding area for coatings.

7.2.1. Pre-Blast Solvent Cleaning

Prior to blast cleaning, all oil, tar, grease, salt and other contaminants shall be removed from the surfaces to be coated. Solvent cleaning SSPC SP 1, high pressure water wash or steam cleaning are the typical methods deemed effective to accomplish contaminant removal. SSPC SP 1 is discussed below.

- Solvent cleaning SSPC SP 1 is a method for removing all visible oil, grease, soil, drawing and cutting compounds, and other soluble contaminants from steel surfaces.
- Solvent cleaning shall be used prior to the specified blast cleaning technique.
- Prior to solvent cleaning, remove foreign matter (other than grease and oil) by one or a combination of the following: brush with stiff fiber, wire brushes or scraping.

7.2.2. Temperature/Humidity Requirements

- Normally, steel surfaces shall not be blasted when the surface temperature is less than 3°C (5°F) above the dew point, when the relative humidity is greater than 85 percent or when there is a possibility that the blasted surface will be subject to wetting before the first coat can be applied.
- Surfaces shall be vacuumed free of blasting abrasive and dust prior to coating.

7.2.3. Surface Area

- No more surface shall be blast-cleaned than can be coated before visible or detrimental rerusting occurs. Blasted surfaces shall be coated no later than at the end of the same workday.
- A 300 mm (12 in) wide strip of uncoated, blasted surface shall be left between coated and unblasted surfaces to prevent damage to the newly dried coating when additional blasting is done. After blast cleaning is resumed, the strip of previously blasted surface shall require only a light brush blast to remove any remaining rust. Cleaning shall be accomplished by holding the cleaning nozzle in a direction away from the coated surface.

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7.2.4. Surface Profiles

Generally, a surface profile of 50–75 T (2–3 mil) is desirable. There are numerous abrasives available to achieve the specified surface profile. Mobil shall approve the specific blasting media as shown on the Mobil Data Sheets I3581C01. Also, the actual surface profile shall be in accordance with the coating manufacturer's requirements.

8. Coating Application General Requirements

The coatings to be used shall be in accordance with the appropriate tables in this MEP. Product descriptions and directions for proper application are contained in the appropriate manufacturer's product data sheets, which the contractor shall supply at the time of the bid, in accordance with D3581C01 of the Mobil Data Sheets

- Oil, grease, soil, dust or foreign matter deposited on the surface after surface preparation shall be removed prior to painting. If rusting occurs after the completion of surface preparation, the surface shall be reblasted in accordance with the original specified method.
- All paint batch numbers and shelf-life dates shall be recorded for future reference in accordance with I3581C01 of the Mobil Data Sheets. No material exceeding the published shelf-life shall be used.
- Paint shall be thoroughly mixed in accordance with manufacturer recommendations immediately prior to application. Recommended mixers are mechanical stirrers, paddle mixers and can vibrators or shakers. Coating material shall not be mixed or kept in suspension by using a bubbling air stream.
- Coating shall be thinned only in accordance with the coating manufacturer's instructions. Only thinners of a type recommended by the coating manufacturer shall be used.
- Where a skin has formed in the container, it shall be redissolved into the body of the material. If the skin cannot be dissolved, the material shall be rejected.

8.1. Coating Methods

Coating shall be applied by one (or a combination) of the following methods:

1. Brushing
2. Roller coating
3. Air spraying
4. Airless spraying

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8.1.1. Spraying Guidelines

When spraying is the required method of coating application, the following shall apply:

1. The equipment used shall be suitable for the intended purpose, be capable of properly atomizing the coating to be applied and be equipped with suitable pressure regulators and gauges in good working order. The air caps, nozzles and needles shall be those recommended by the spray equipment manufacturer for the coating being sprayed. The equipment shall be kept in satisfactory condition to permit proper coating application.

2. Traps or separators shall be provided to remove oil and condensed water from the air. They shall be of adequate size and drained periodically during application. The air from the spray gun impinging against the surface shall show no signs of condensed water or oil. A blotter test shall be performed.

3. The pressure on the material in the pot and of the air at the gun shall be adjusted for optimum spraying effectiveness. Moreover, the pressure on the material in the pot shall be adjusted, when necessary, for changes in elevation of the gun above the pot.

4. The atomizing air pressure at the gun shall be high enough to properly atomize the coating, but not so high as to cause excessive fogging, evaporation of solvent or loss by overspray.

5. Spray equipment shall be kept sufficiently clean so that dirt, dried coating and other foreign materials are not deposited on the coating. Any solvents left in the equipment shall be completely removed before applying coatings.

6. Areas inaccessible to the spray gun shall be coated by a method acceptable to Mobil. Spray lances can be used to internally coat nozzles, couplings, etc.

8.2. Chemically Cured Coatings

Chemically cured coatings generally shall not be applied at air or surface temperatures below 18°C (65°F) or when relative humidities are above 85 percent. (The coating manufacturer's recommendations shall be consulted in each case for possible special temperature requirements.) No coatings shall be applied to a surface at a temperature that will cause blistering, porosity or otherwise be detrimental to the service life of the coating.

8.3. First Coat

Surface areas cleaned to base material shall be coated with the specified first coat on the same day that surface preparation has been completed and before detrimental rerusting

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occurs. This first coat shall adequately cover all blast profile peaks to avoid rust breakthrough.

In order to avoid bridging effects on tanks and vessels, all weld areas shall be hand brushed (stripe coated or precoated) with the coating (thinned in accordance with manufacturer's recommendations) before proceeding with application of the first coat.

8.4. Recoating

- Surfaces shall not be recoated until the preceding coat has properly dried or cured. The surface may be considered ready for recoating when the next coat can be applied without the development of coating film irregularities, such as lifting or loss of adhesion of the undercoat. However, the minimum or maximum drying or curing time specified by the coating manufacturer shall be the acceptable recoat period.
  - A minimum of 152 mm (6 in) overlap over the existing sound coating shall be considered as the minimum necessary for sealing pinholes resulting from fringe blasting.
  - Details of the drying and curing requirements for each system specified shall be obtained from the coating manufacturer, in accordance with D3581C01 of the Mobil Data Sheets. Coating shall not be force dried under conditions that will cause wrinkling, blistering or formation of pores, or that will be detrimental to its condition or appearance.
  - Newly coated surfaces shall be protected to the fullest extent possible from rain, condensation, contamination, snow and freezing, until the coating has cured.
- For thin-film coatings, successive coats shall be of different colors.
- Where the specified dry film thickness is not achieved, additional coats shall be applied until the proper thickness is obtained. The film thickness shall not affect appearance or service life of the coating.

8.5. Finished Applications/Repairs

- All coating application shall be performed by qualified journeymen, in a workmanlike manner, conforming to all safety standards, environmental regulations, codes and standards.
  - The finished application shall be uniform in color, texture and appearance. The work shall be free of sags, wrinkles and other unwanted defects.
  - Any deficiencies shall be corrected by the contractor at contractor's expense.
- Coated surfaces shall not be handled or walked on until the coating has dried.
- Areas that have been damaged during handling shall be recleaned and retouched with the same number of coats and types of coating as were previously applied to the base material or they shall be repaired with an approved patch repair procedures.

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9. Special Notes on Surface Preparation and Coating Application

9.1. Shop-Applied Coatings

Use of shop-applied coatings shall be considered when economical and feasible for new construction.

9.2. Field-Applied Coatings

Field application of coatings shall be conducted in accordance with all the requirements of this MEP.

- Repair of damaged shop-applied or field-applied coatings will be required to ensure adequate performance. Repair of defective or damaged areas shall be accomplished in the same manner as the original coating, with regard to surface preparation prior to recoating, unless alternative methods are approved in accordance with D3581C01 of the Mobil Data Sheets.
- Under certain conditions, re-application or maintenance of an existing coating that has been in service can be conducted.
  - However, this is rarely done because of potential incompatibility problems between new and old coatings.
  - If the above approach will be attempted, the coatings shall be tested for compatibility with the paints with which they are to be overcoated to ensure that lifting, wrinkling or other deleterious effects of the existing coating will not occur.

10. Types of Coatings

There are several different types of coatings that can be specified for internal use. They include the following:

1. Non-reinforced thin-film coatings [less than 0.5 mm (20 mil) dry film thickness]
2. Glass flake reinforced coatings
3. Thick-film coatings, reinforced and unreinforced (greater than 0.5 mm [20 mil] dry-film thickness)
4. Cement linings

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Each of these types of coatings has different properties, application requirements and associated costs. Each will perform differently. To effectively choose the appropriate coating, all of these factors need to be considered.

10.1. Non-Reinforced Thin-Film Coatings

This type of coating can be used for tanks, vessels, piping and tubulars. The thin-film coatings are based on epoxy or epoxy-phenolic resins. Each generic has its own specific properties, chemical exposure and temperature limitations. The pressure on the coating will also effect its performance.

10.2. Glass Flake Reinforced Coatings

This type of coating can be used for tanks and vessels. It is normally used in abrasive environments and applied thicker than most thin-film coatings.

10.3. Reinforced Thick-Film Coatings

This type of coating can be used for tanks. Typical coatings for this class include vinyl esters, polyesters, polyurethanes and epoxies. These materials are reinforced with fiberglass in the form of fibers or mats.

10.4. Cement Linings

Cement lining is generally used in water lines. It may have to be considered for potable water as it does not impart any taste or odor. For application in potable water, local codes or regulations may cover the use of cement.

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Appendix: Seam Sealing of Riveted or Bolted Tanks

This Appendix covers procedures and materials for using epoxy resins to seal riveted or bolted plate seams in aboveground storage tanks. This Appendix is applicable to petroleum refineries, petrochemical plants, marketing plants and E&P facilities.

1. General

The procedures and requirements of this MEP pertaining to surface preparations, materials application, materials handling and health and safety shall be followed except as amended herein.

- Corroded or perforated plates shall be repaired by welding a patch plate, or by some other mechanical repair method, in accordance with API STD 653 and applicable codes and standards.
- Riveted or bolted plate seams shall be sealed in accordance with Section 2 of this Appendix.
- If, prior to applying the seam sealer, it is necessary to remove lead-based paints from a tank's exterior, this shall be done in accordance with all appropriate laws and regulations.
- Compatibility between sealing resins and coatings of various manufacturers shall be considered prior to selection of coating materials.

2. Sealing of Seams

This Section covers procedures for sealing leaking or weeping seams in plates joined by riveting or bolting where structural reinforcement is not required.

2.1. Sealing Procedure

Seams shall be sealed by:

1. Blast cleaning the seams to be sealed
2. Mechanically caulking wide seam gaps, if required below
3. Applying epoxy seam sealer

For best results, allow the seams to drain or vent trapped hydrocarbons for at least 24 hours after initial blasting. Reblasting shall then be required prior to applying the mechanical caulk and the seam sealer.

2.2. Sealing Methods

The method of seam sealing shall depend on the width of the seam gap. Gap widths and their corresponding sealing methods are classified as follows:

- <1.6 mm ($^1/_{16}$ in) in width: Apply epoxy seam sealer directly to the seam as specified in this Appendix.
- 1.6–9.5 mm ($^1/_{16}$–$^3/_8$ in): Mix a small amount of clean, dry silica sand with epoxy seam sealer and pack the seam gap. Apply epoxy seam sealer directly to seam.
- >9.5 mm ($^3/_8$ in) in width: Mechanically caulk the gap with a filler material such as "Oakum," a fiber wool product. Finish flush with the plate edge. Apply epoxy seam sealer directly to the seam.

2.3. Sealing Requirements

Sealing of plate seams may be done on either the interior or the exterior of the tank. External seam sealing is acceptable for the tank shell. However, preferably both the interior and exterior seams shall be sealed if the tank is out of service.

- If possible, when external sealing is required, the tank shall be completely depressurized and the liquid level kept below the level of the seams being sealed during the entire sealing operation. Metal temperature shall be a minimum of 18°C (65°F) or as specified by the sealer manufacturer.
- Seam sealer applied externally shall be allowed to cure for a minimum of 24 hours at 24°C (75°F) metal temperature before the sealer is subjected to pressure. An example is when the liquid level of the tank is raised.
- For internal sealing, a minimum curing time of four days at 24°C (75°F) metal temperature shall be allowed before placing the tank in service.
- Application procedures, such as product curing time and temperature requirements, shall be in accordance with the requirements of the seam sealer manufacturer's product data sheets.

2.4. Materials

Generic products and type of application that shall be used for sealing are:

- Epoxy seam sealer, such as Valspar 46-X-2 or equivalent: For hand application by short-bristle brush, putty knife or glove to a minimum of 500 μm (20 mil) dry-film thickness per coat.
- Sprayable epoxy rivet and seam sealer, such as Valspar 46-X-14 or equivalent: For application only with special two-component spray gun at a dry-film thickness of 1000–1500 μm (40–60 mil).

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This operation shall be performed in accordance with all applicable volatile organic compound (VOC) regulations. Appropriate personnel protective equipment shall be worn when applying seam sealers.

2.5. Surface Preparation

Surfaces shall be prepared by blast cleaning to a white metal finish (SSPC SP 5). Appropriate respiratory protection shall be worn during surface preparation. It is recommended that abrasives containing free silica be avoided.

- The blasted area shall include:
  - The seam to be repaired
  - A 75 mm (3 in) wide strip on either side of the seam
  - All bolts and rivets within this area
- The blasted area shall be solvent washed with the manufacturer's recommended thinner immediately prior to application of the seam sealer in order to remove any oil that may have seeped onto the cleaned surface. Appropriate personnel protective equipment shall be worn while mixing and handling solvents.

2.6. Application of Seal Coat

Materials shall be mixed, handled and applied in accordance with product directions. Appropriate personnel protective equipment shall be worn while mixing and handling solvents. Either epoxy seam sealer or sprayable epoxy rivet and seam sealer shall be used as a seal coat as follows:

1. Epoxy seam sealer shall be applied vigorously to seams, blasted areas and rivet or bolt heads to ensure that the surface has been completely wetted by the epoxy. Follow that immediately with an application of a light fillet of epoxy seam sealer to the seams and a heavy seal coat swirled around the rivets and bolts. Minimum total dry-film thickness of all coats shall be 1500 μm (60 mil).
2. Sprayable epoxy rivet and seam sealer shall be sprayed in a multipass operation to obtain a full uniform thickness on seams and completely around the rivets and bolts. Generally, a three-pass application shall ensure sealing. The first two passes shall consist of one pass from each side of the seam at a 45 degree angle; the third pass shall be perpendicular to the surface. Apply coating to 1000–1500 μm (40–60 mil) dry-film thickness.
3. After the seam sealer has dried thoroughly, the coating shall be inspected for continuity and bond. If defects are found, the affected areas shall be solvent cleaned and recoated.

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2.7. Finish Coats–External Surfaces

Finish coats are classified as follows:

- Alkyd Finishes: Allow epoxy seam sealer a curing interval of approximately four hours at 24°C (75°F) metal temperature before overcoating.
- Epoxy Finishes: Epoxy seam sealer shall be cured a minimum of 16 hours at 24°C (75°F) before being overcoated. To preserve the blast on adjacent surfaces, allow the epoxy seam sealer a four-hour cure interval and then apply a thin (25 μm [1 mil] dry) holding coat, minimizing the overlap onto the seam sealer.

3. Coating Index

Compatibility between the seam sealer and the product(s) to be stored in the tank shall be considered. Fuels with additives such as MTBE or oxygenates may not be compatible with the seam sealers.

Table A–1 references the use of Valspar Corporation products or equivalents. Contact the MRDC Materials Engineering Section for acceptable equivalents. Products from the other suggested vendors will be considered and require Mobil approval prior to use.

Table A–1: Index of Coating Materials

Generic Product	**Examples**	**Recommended Dry-Film Thickness**		**Color**
		μm	**mil**	
Epoxy seam sealer	Valspar 46-X-2 or equivalent	500 minimum	20 minimum	Gray
Sprayable epoxy rivet and seam sealer	Valspar 46-X-14 or equivalent	1000–1500	40–60	Blue (formerly Green)

4. Inspection

- Surfaces to be coated shall be examined for unsatisfactory conditions (such as sharp edges or weld splitter) that will adversely affect execution, permanence or quality of work.
- The blast-cleaned area shall be inspected and approved prior to application of the seam sealer.

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- The approximate wet-film and dry-film thickness of the coatings shall be recorded.
- A "holiday" check, using wet sponge or spark equipment, shall be conducted to confirm that the seam sealer is free from pinholes and discontinuities.

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